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A MODEL

FOR SUSTAINABILITY



ANNUAL REPORT
2004

BAYTEX
ENERGY TRUST

CORPORATE PROFILE

Baytex Energy Trust is a Calgary based energy income trust created through the reorganization of Baytex Energy Ltd. in September 2003. Baytex is engaged in the development, acquisition and production of oil and natural gas in the Western Canadian Sedimentary Basin.

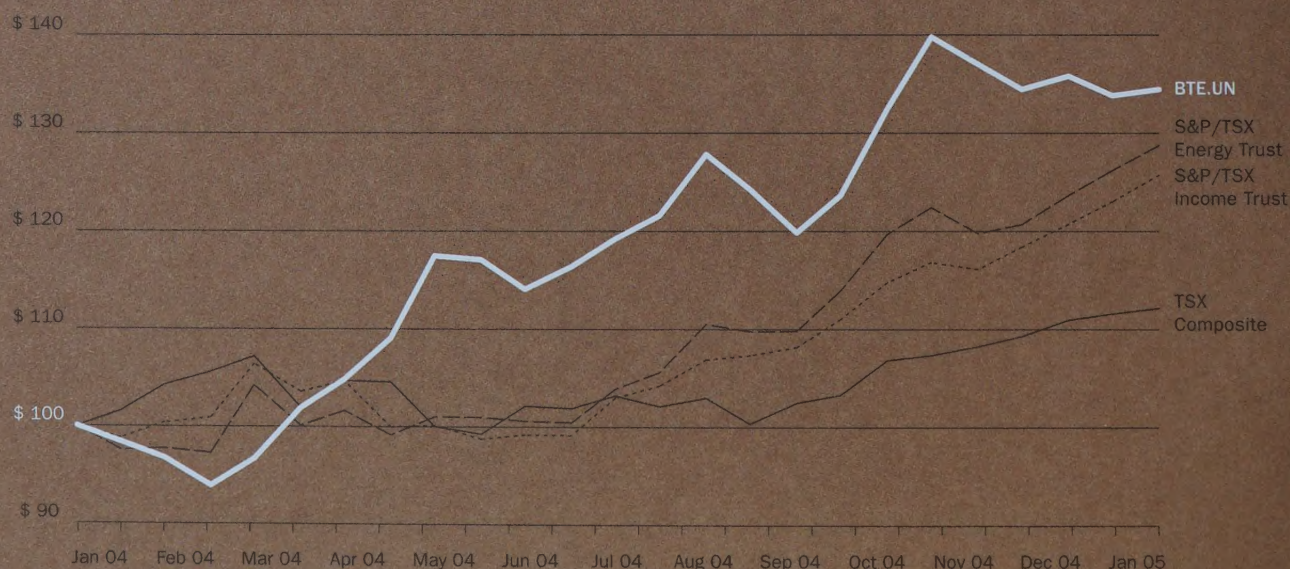
The base of operations includes a high quality portfolio of operated properties and development prospects with significant upside potential. During 2004, the oil and gas assets generated average production of 34,022 boe per day comprised of 73 percent oil and 27 percent natural gas.

Baytex maintains its production and reserve base through a combination of internal property development and the selective acquisition of complementary assets.

Baytex is focused on delivering consistent returns to unitholders through prudent operational and financial management. Baytex is traded on the Toronto Stock Exchange under the symbol BTE.UN.

TOTAL RETURN COMPARISON VALUE OF A \$100 INVESTMENT

Baytex trust units outperformed the TSX Composite, S&P/TSX Income Trust and Energy Trust indices during 2004 on a total return basis.



HIGHLIGHTS⁽¹⁾

(\$ thousands, except per-share data)

	2004	2003	change %
FINANCIAL			
Petroleum and natural gas sales	420,400	403,022	4
Cash flow from operations ⁽²⁾	136,012	138,233	(2)
Per unit – basic	2.17	2.56	(15)
– diluted	2.07	2.49	(17)
Cash distributions paid or declared	113,063	33,382	239
Per unit	1.80	0.60	200
Net income	13,763	35,844	(62)
Per unit – basic	0.22	0.66	(67)
– diluted	0.21	0.62	(66)
Net capital expenditures	280,666	48,383	480
Total net debt	422,044	213,572	98
Trust units outstanding at December 31 (thousands) ⁽³⁾	68,817	64,714	6

OPERATING

Production			
Light oil and NGLs (bbls/d)	2,172	2,273	(4)
Heavy oil (bbls/d)	22,073	23,911	(5)
Total oil and NGLs (bbls/d)	24,875	26,184	(5)
Natural gas (mmcf/d)	54.9	63.0	(13)
Barrels of oil equivalent (boe/d @ 6:1) ⁽⁴⁾	34,022	36,686	(7)
Reserves, proved and probable⁽⁵⁾			
Oil and NGLs (mbbls)	93,843	88,517	6
Natural gas (mmcf)	155,100	106,300	46
Barrels of oil equivalent (mboe @ 6:1)	119,686	106,300	13

- (1) Baytex Energy Trust commenced operations on September 2, 2003 as a result of the reorganization of Baytex Energy Ltd. As the Trust is considered the successor organization to Baytex Energy Ltd. for reporting purposes, comparative information is provided for the year ended December 31, 2003. Pursuant to the Plan of Arrangement effecting the reorganization, certain assets were not transferred to the Trust. Accordingly, results of the corresponding periods in 2003 and 2004 are not directly comparable.
- (2) Cash flow from operations and cash flow from operations per unit are non-GAAP terms that represent cash generated from operating activities before changes in non-cash working capital and other operating items. The Trust's cash flow from operations may not be comparable to other companies. The Trust considers cash flow a key measure of performance as it demonstrates the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.
- (3) Number of trust units outstanding includes the conversion of exchangeable shares at the respective exchange ratios in effect at the end of the reporting periods.
- (4) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
- (5) Reserves information as at December 31, 2004 and 2003 is prepared in accordance with NI 51-101.

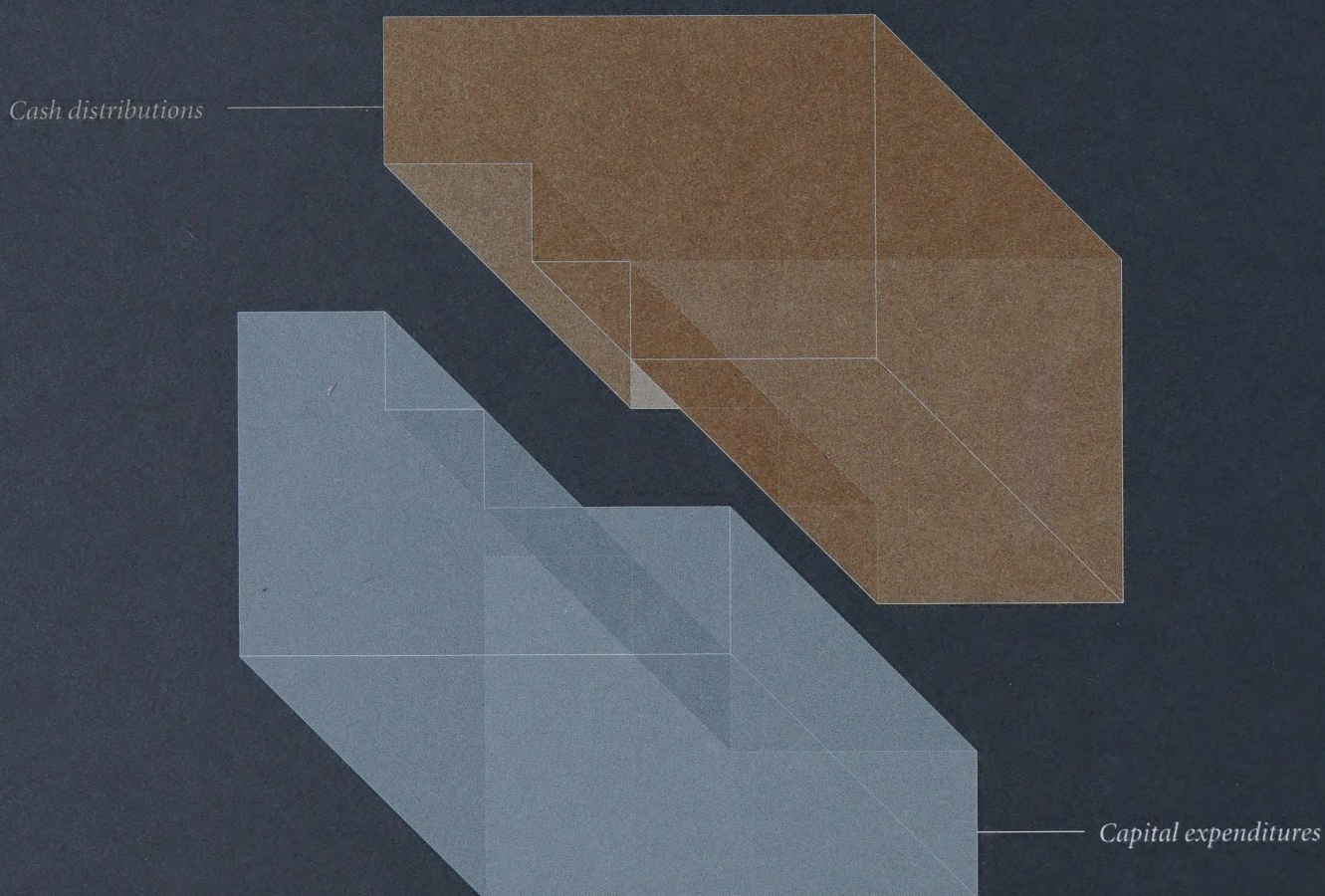
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SELF-SUSTAINING

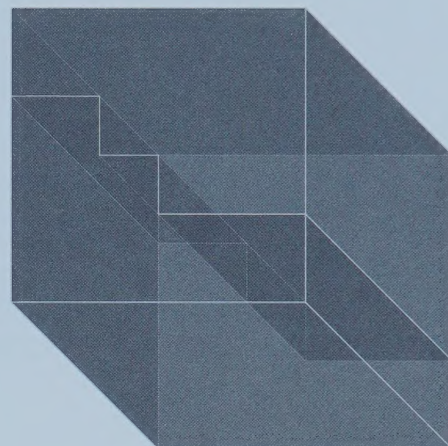
BUSINESS MODEL

OPERATING CASH FLOW



THE SELF-SUSTAINING BUSINESS MODEL ensures that annual operating cash flow is sufficient to maintain stable distributions and production year over year. Achieving a self-sustaining business model reduces or eliminates the need to fund these items through increased debt or trust unit issuance.

OPERATING CASH FLOW Based on the current commodity price outlook, Baytex's operating cash flow for 2005 should be sufficient to fully fund all planned capital spending and monthly distributions.

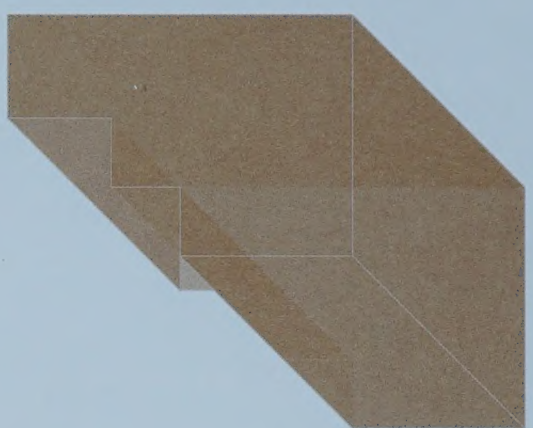


MESSAGE TO UNITHOLDERS

In 2004 we succeeded in making Baytex a better and more sustainable trust.

2004 was a remarkable year! For the global oil and gas industry, it was a defining year in convincing more stakeholders that commodity prices could remain at higher than historical levels. For the Canadian oil and gas industry, the income trust phenomenon continued to gain acceptance and income trusts dominated the merger and acquisition market during the year. For Baytex Energy Trust, 2004 was our first full year of operations as an income trust. Upon conversion from our previous exploration and production company model, where delivering superior growth was the primary objective, our mandate has been re-defined to one of building sustainability. We carefully executed this business plan in 2004. We added key individuals to our management team, and we strengthened the core of our asset base in both our Heavy Oil District and Conventional Oil and Gas District. By all measures, we succeeded in making Baytex a better and more sustainable trust.

For our heavy oil operations, we followed our game plan of realizing on our internal opportunities and did not add any barrels through acquisition. The most exciting development for us was the successful introduction of Seal as a high potential resource play that could underpin our heavy oil operations for years to come. We bought our first sections of land at Seal in 2001 and quietly built it into a 100 section land position at 100 percent working interest. We conducted a seven-well test program in the winter of 2004 to gain information on oil and reservoir quality in our various land blocks. After analyzing this data, we selected the western land block as our first production test site. Two horizontal production wells were drilled in the late December and early January and are producing at approximately 200 barrels per day per well. We booked approximately 1.1 million barrels of proved reserves and 1.5 million barrels of proved plus probable reserves at year-end 2004 which were assigned to five wellbores by our independent



CASH DISTRIBUTIONS Baytex has maintained its monthly distribution at \$0.15 per unit since its conversion to an income trust in September of 2003. Baytex plans to maintain its monthly distribution at \$0.15 per unit in 2005 barring a significant decline in commodity prices.

evaluators. We are following up this success in the first quarter of 2005 with a non-producing, six vertical well test program to further delineate this 20-section land block. We are also drilling four more horizontal production wells and all of them are expected to be on production by the end of the first quarter. Industry results in this area show that each prospective section of land could hold up to 2.5 million barrels of recoverable reserves with aggregate initial production of 2,000 barrels per day. It took Baytex four years to sell its first barrel of production and to record its first barrel of reserve at Seal. We are encouraged that Seal could grow to be our largest producing area in the coming years.

While this exciting development was happening in our Heavy Oil District, we actually spent over three-quarters of our 2004 capital expenditures to bolster our conventional oil and gas operations. Through two separate transactions completed late in the year, one in September and one just ten days prior to year-end, we added 6,300 boe per day of natural gas weighted production to our conventional district. This production is from two very focused areas in Southern Alberta and Northeast British Columbia, virtually all Company-operated with 80 percent to 100 percent working interests. We acquired the production at \$31,750 per producing boe and \$11.62 per proved plus probable boe of reserves. These metrics compared favourably to the industry average of around \$40,000 per producing boe and \$12.50 per proved plus probable boe in over \$7 billion of transactions in 2004. In addition to these accretive acquisition metrics, more importantly, these transactions significantly enhanced our development inventory for our conventional oil and gas operations. For 2005, we are projecting a production mix of 60 percent heavy oil and 40 percent natural gas and light oil on a boe basis. For our 2005 cash flow, it should approximate an even split due to the higher netback from natural gas and light oil. We welcome this balance as it helps us to manage through the ups and downs of various commodity cycles, and we are pleased to have a balanced portfolio of opportunities to pursue sustainability in the future.

Our 2004 capital programs totaled \$280 million. With the success of our acquisition efforts, we cut back exploration and development spending from the original budget of \$105 million to \$94 million, resulting in the drilling of 138 wells compared to the budget of 170 wells. Even with this scaled back program, our drilling activities in 2004 placed us as the most active operator amongst energy trusts in Saskatchewan and the seventh most active operator amongst energy trusts in Alberta, evidencing



CAPITAL EXPENDITURES Baytex has a \$100 million exploration and development capital budget for 2005 with \$65 million allocated to heavy oil and \$35 million for natural gas and light oil. This level of capital expenditures should support average production of 36,000 boe per day consisting of 22,000 boe per day of heavy oil, 60 mmcf/d of natural gas and 4,000 barrels per day of light oil and NGL's.

the business strategy and the internal development opportunities of Baytex. Our overall finding, development and acquisition cost was \$10.70 per proved plus probable boe. We increased the natural gas and light oil component of our reserves base to 33 percent. We replaced our production during the year by 210 percent. We extended our reserves life index to 9.1 years. And, we improved our net asset value to \$9.84 per unit based on forecast prices utilized by our independent evaluators discounted at 10 percent. Our net asset value based on constant prices at year-end 2004 discounted at 10 percent improved to \$16.26 per unit. These constant price assumptions are more closely reflective of current prices in the futures market than those under the forecast price scenario. By our estimation, Baytex should be one of very few oil and gas trusts that are trading below net asset value measured under similar parameters.

Baytex's cash flow from operations in 2004 was negatively affected by our crude oil hedging program during the year. This program was established in the summer of 2003 with the objective of protecting cash flow in the event of a significant decline in crude oil prices. Management determined that as we embarked on our first year of operations as an income trust, our top priority would be to protect cash flow for distribution purposes. In total, 15,000 barrels per day for the year was contracted with an average cap price of US\$29.75. Rapidly increasing demand for crude oil from China and other developing countries in Asia, combined with the volatile geopolitical situation in the Middle East, caused oil prices to surge throughout 2004 to unprecedented levels. WTI crude averaged US\$41.40 during the year, exceeding the previous high of US\$37.37 set in 1980. This unforeseen strength resulted in oil hedging losses of \$82.4 million during the year for Baytex, representing 38 percent of cash flow before hedging activities.

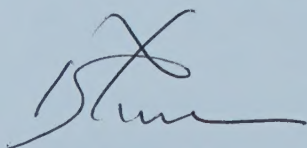
Continuing appreciation of the Canadian currency also negatively affected cash flow in 2004. The Canadian dollar began the year at US\$0.7737 and ended the year at US\$0.8308. From the beginning of 2003 to the end of 2004, the Canadian dollar had appreciated an astonishing 31 percent. While the associated effect on oil and gas cash flow is very significant, the impact on Baytex is partially offset because all of Baytex's long-term debt is denominated in U.S. dollars. Our foreign exchange hedging program further mitigated the impact of the Canadian dollar's appreciation. During 2004, we realized a gain of \$4.3 million from our foreign exchange hedging contracts.

RETURN ON INVESTMENT Baytex trust units returned a combined 34 percent to investors in 2004, surpassing the S&P/TSX Energy Trust Index, Income Trust Index and Composite Index. Baytex is well positioned to again deliver superior returns to investors in 2005.

Baytex has maintained our monthly distribution at \$0.15 per unit since our conversion to an income trust in September 2003. Total distributions in 2004 amounted to \$113.1 million, representing a payout ratio of 83 percent. This high payout ratio is due to the hedging losses incurred, particularly in the fourth quarter when such losses were \$27.6 million and the payout ratio reached 103 percent. Excluding hedging losses, the payout ratio in the fourth quarter would have been 52 percent. With the expiry of the 2004 hedging contracts, Baytex is projecting a significant improvement in cash flow. Under the 2005 hedging program, 8,000 barrels per day have been collared between WTI US\$35.00 and US\$42.55, and US\$9.0 million per month have been collared between the average exchange rates of \$0.8000 and \$0.8218. These contracts will provide substantial downside protection to Baytex's cash flow while allowing for participation in the benefits of current commodity prices. Baytex plans to maintain our monthly distributions at \$0.15 per unit in 2005 barring a significant decline in commodity prices. The lower payout ratio in 2005 should bring the cumulative payout ratio to our target range of 60 percent to 70 percent. Based on current commodity price outlook, our 2005 cash flow is expected to be sufficient to fully fund all of our planned capital spending and our \$0.15 per unit monthly distributions. And that is the sustainability we strive to achieve.

The Baytex trust units returned a combined 34 percent to investors in 2004, surpassing the S&P/TSX Energy Trust Index, the Income Trust Index and the Composite Index. Economic conditions look to continue to be favourable for the income trust sector in 2005. With solid fundamentals and a still relatively under-valued unit price, Baytex is well positioned to again deliver superior returns to its investors.

On behalf of the Board of Directors,

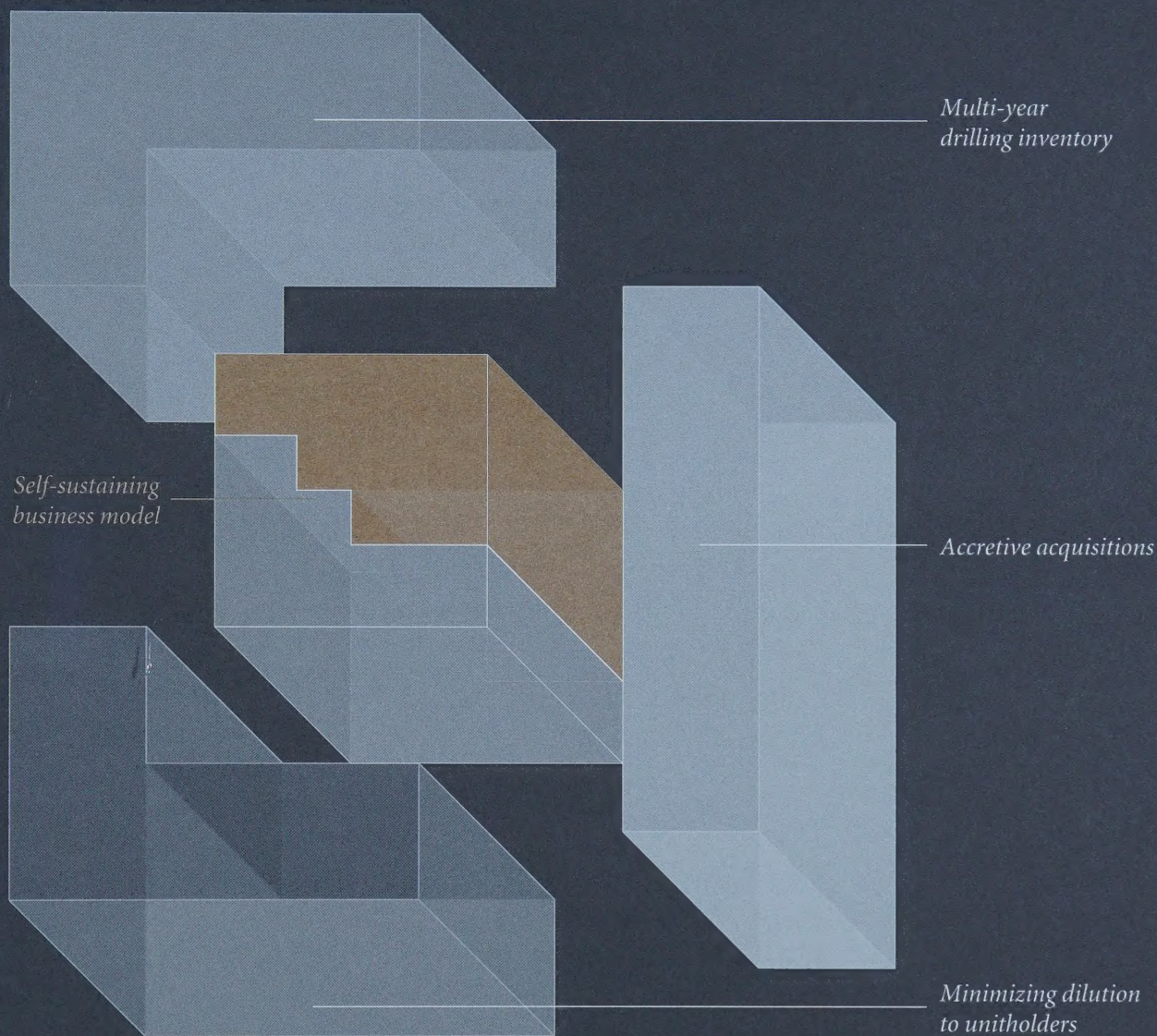


RAYMOND T. CHAN, CA
President and Chief Executive Officer

March 8, 2005

INVESTMENT

MERITS



OUR STRATEGY Baytex strives to maintain the self-sustaining business model by utilizing its multi-year internal drilling inventory combined with selective acquisitions in key operating areas. These operating advantages combined with the self-sustaining model will minimize dilution to unitholders over time.

PRINCIPAL

PROPERTIES



BAYTEX'S OPERATIONS are organized into two business districts, each with its own extensive portfolio of assets and opportunities.

Regarding this MD&A The following discussion and analysis, dated March 7, 2005, should be read in conjunction with Baytex Energy Trust's (the "Trust" or "Baytex") audited consolidated financial statements for the fiscal years ended December 31, 2004 and 2003. Per barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations and cash flow per unit are not measurements based on generally accepted accounting principles ("GAAP"), but are financial terms commonly used in the oil and gas industry. Cash flow represents cash generated from operating activities before changes in non-cash working capital, deferred charges and other assets and deferred credits. The Trust's determination of cash flow may not be comparable with the calculation of similar measures for other entities. The Trust considers it a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments.

The Trust also uses certain key performance indicators and industry benchmarks such as operating netbacks ("netbacks"), finding, development and acquisition costs ("FD&A"), recycle ratio and payout ratio to analyze financial and operating performance. These key performance indicators and benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

This discussion and analysis contains forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of the Trust. The projections, estimates and beliefs contained in such forward-looking statements necessarily involve known and unknown risks and uncertainties, including the business risks discussed in the MD&A as at and for the years ended December 31, 2004 and 2003, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Readers should not place undue reliance on any such forward-looking statements, which speak only as of the date they were made. The Trust is not obligated to publicly update or revise the forward-looking statements relating to future events or future performance to reflect any change in management's expectations or events.

The Trust was established on September 2, 2003 under a Plan of Arrangement involving the Trust, Baytex Energy Ltd. (the "Company") and Crew Energy Inc. ("Crew"). The Trust is an open-ended investment trust created pursuant to a trust indenture. The Company is a subsidiary of the Trust.

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of the Company and its subsidiaries and partnership. After giving effect to the Plan of Arrangement,

the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor to Baytex Energy Ltd. The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles.

2004 OVERVIEW

ACQUISITIONS

Effective September 22, 2004, the Company acquired all of the outstanding shares of a Calgary based private oil and gas company for a cash consideration of \$109 million. The results of its operations have been included in the consolidated financial statements of the Trust since the effective date. This acquisition added approximately 3,000 boe per day of production comprised of 12 mmcf/d of natural gas and 1,000 barrels per day of light oil and NGLs from three geographically-focused areas in southern Alberta. Subsequent to the acquisition, the private company was amalgamated with the Company.

Effective December 22, 2004, the Company acquired oil and natural gas interests in the West Stoddart area of northeast British Columbia for a total cash consideration of \$90 million. This property added approximately 3,300 boe per day of primarily high netback liquids-rich natural gas production comprised of 10.0 mmcf/d of natural gas, 1,300 barrels per day of NGLs and 330 barrels per day of light oil. The production is from three properties near Fort St. John, B.C. generally with year-round access for efficient operations and capital activities.

2004 Acquisition Metrics

- cost per producing boe per day: \$31,750
- cost per proved boe: \$14.63
- cost per proved plus probable boe: \$11.62

OPERATIONS REVIEW

PRINCIPAL PROPERTIES

Baytex's crude oil and natural gas operations are organized into two operating districts – the Heavy Oil District and the Conventional Oil and Gas District. Each district constitutes an extensive portfolio of operated properties and development prospects with considerable upside potential. Baytex has established skilled technical teams to operate each district. Each team has a mandate to apply its specific knowledge and expertise to its operating area. This focused approach aids in the evaluation of exploration, development and acquisition opportunities and improves cost efficiency.

HEAVY OIL DISTRICT

The Heavy Oil District accounts for approximately 60 percent of the Trust's current production and approximately three-quarters of its reserves and 50 percent of cash flow from operations. Heavy oil operations consist largely of cold conventional production from wells with multi-zone potential. Production is generated primarily from vertical, slant and horizontal wells using progressive cavity pump technology to generate large volumes of heavy oil combined with gas, water and sand. Initial production from these wells usually averages between 40 and 100 barrels per day of low gravity crude ranging from 11 to 18 API. Once produced, the oil is trucked or pipelined to markets in both Canada and the United States. After being sold by Baytex, the crude oil is then upgraded into lighter grades of crude or refined into petroleum products such as fuel oil, lubricants and asphalt.

In 2004, production in the Heavy Oil District averaged 22,700 barrels per day of heavy oil and 8.9 mmcf/d of natural gas (24,200 boe per day). Baytex drilled 115 gross (113.7 net) wells in the heavy oil district resulting in 95 gross (95.0 net) oil wells, three gross (2.2 net) gas wells, seven gross (6.5 net) stratigraphic test wells, and 10 gross (10.0 net) dry and abandoned wells, for a success rate of 91.3 percent.

The ability to generate relatively low cost replacement production is one of the key elements of the Trust's sustainability.

The Heavy Oil district possesses a large inventory of development projects within the west-central Saskatchewan, Cold Lake/Ardmore, and Peace River/Seal heavy oil deposits. The ability to generate relatively low-cost replacement production through conventional cold production methods is one of the key elements of the Trust's sustainability.

The Trust will continue to build value through internal property development and selective acquisitions. Future heavy oil activity will focus on the development of the Seal and Ardmore properties along with continued infill drilling at the adjacent Cold Lake property and throughout the Saskatchewan properties. Company net undeveloped lands in this district totaled 344,892 acres at year-end 2004.

ARDMORE – ALBERTA

Ardmore is one of the key heavy oil development and production areas for the Trust. Acquired in 2002 with production of 2,200 barrels per day, Ardmore has been developed in the Sparky, McLaren and Colony formations. Average production during 2004 was 4,200 barrels per day of oil and 1.0 mmcf/d of natural gas (4,400 boe per day). Current production is 3,800 barrels per day of oil and 950 mcf/d of natural gas (4,000 boe per day). Baytex has applied leading-edge slotted-liner production technology to improve production and increase wellbore stability. Slotted-liner wells in the area are capable of producing up to 300 barrels per day of heavy oil and continue to be used extensively for pool development projects. Twenty-six oil wells and three dry wells were drilled in the area during 2004 and 20 to 25 wells are anticipated to be drilled during 2005. During 2004, operating expenses were reduced to \$5.50/bbl primarily by building a water disposal facility and conserving solution gas produced in conjunction with the heavy oil. It is expected that operating expenses will be further reduced as a result of the construction of a sand disposal facility in late 2004. The Trust also added 6,500 acres of new lands through Crown land sales in 2004 that are prospective for Colony oil pool development. Company net undeveloped lands were 39,120 acres at year-end 2004.

COLD LAKE – ALBERTA

Baytex acquired the Cold Lake heavy oil property in 2001. This year-round drilling area is located on the Cold Lake First Nations lands, with heavy oil production generated largely from the Colony formation. Average production was 1,000 barrels per day during 2004. The Trust drilled 12 oil wells and three dry wells in the Cold Lake area during 2004. Up to 15 new drills are anticipated during 2005. Company net undeveloped lands were 18,062 acres at year-end 2004.

SEAL – ALBERTA

The Seal property is a highly prospective property located in the Peace River oil sands area of northwest Alberta. The Trust holds a 100 percent working interest in approximately 96 sections of land, of which 42 sections were acquired in 2004. The Seal oil deposits can be produced through horizontal well-bores at initial rates of approximately 200 barrels per day per well without the use of capital intensive steam

injection methods. A seven-well stratigraphic test program completed during the first quarter of 2004 has led to the Trust's current development program on the western block of these land holdings. Two horizontal wells drilled at the end of 2004 are currently producing a total of approximately 400 barrels per day. The prospective undeveloped area of the western block is over 25,000 acres. During 2005, Baytex plans to drill up to six additional stratigraphic test wells to further delineate this land block and up to 15 horizontal

producers in the immediate area that are currently producing. In addition, other industry operators are currently drilling horizontal production wells on adjoining sections that will help define the productive capability of the Trust's lands. Company net undeveloped lands in this area were 63,680 acres at year-end 2004.

The Seal area in the Peace River region of Alberta is one of the most active areas for primary heavy oil development in Canada.

TANGLEFLAGS – SASKATCHEWAN

Baytex acquired the Tangleflags property in 2000. Tangleflags is characterized by multiple-zone reservoirs with production from the Colony, McLaren, Waseca, Sparky, General Petroleum and Lloydminster formations. Provincial government regulations generally prohibit production from more than one formation at a time. As such, this property possesses long-term development potential from a considerable number of up-hole recompletion opportunities. Average production during 2004 was approximately 3,800 barrels per day of heavy oil and 1.2 mmcf/d of natural gas (4,000 boe per day). Ongoing projects in the area include up to 15 development wells during 2005, uphole recompletions after depletion of deeper producing intervals, and optimization of the solution gas gathering system. Company net undeveloped lands were 11,160 acres at year-end 2004.

CARRUTHERS – SASKATCHEWAN

The Carruthers property was obtained by Baytex in 1997. The property consists of separate "North" and "South" oil pools in the Cummings formation. Typical vertical oil wells initially produce approximately 40 barrels per day with ultimate recoveries of approximately 60,000 barrels of reserves. During 2004, average production was approximately 3,200 barrels per day of heavy oil and 850 mcf/d of natural gas (3,300 boe per day). The Trust drilled 1.2 net natural gas wells and 14 net oil wells in South Carruthers and three net horizontal oil wells in North Carruthers during 2004. This area represents a relatively stable production base with continued development drilling expected to total 10 to 15 wells annually. Company net undeveloped lands were 14,425 acres at year-end 2004.

MARSDEN/EPPING/MACKLIN/SILVERDALE – SASKATCHEWAN

This area of Saskatchewan is characterized by low-access costs and higher quality oil of 13 to 18 API gravity and low sand content. Initial production rates are typically 70 barrels per day and primary recovery factors can be as high as 30 percent of the original oil in place. This oil is also receptive to waterflood recovery schemes to further increase recovery. Average production in this area during 2004 was approximately 4,600 barrels per day. Twenty oil wells were drilled in 2004, increasing production to over 4,900 barrels per day by year-end. In addition, ongoing flow-line installation and water disposal projects have combined to keep operating costs below \$5.50/bbl. Drilling in 2005 will add up to 15 new oil wells, mostly through development of the Macklin pool. In Epping, waterflood and solution gas tie-in projects are planned for 2005. Company net undeveloped lands were 20,932 acres at year-end 2004.

CONVENTIONAL OIL AND GAS DISTRICT

The Conventional Oil and Gas district produces light and medium gravity crude oil, natural gas and natural gas liquids from various fields in Alberta and British Columbia. In 2004, production averaged 46.0 mmcf/d of natural gas and 2,200 barrels per day of hydrocarbon liquids (9,800 boe per day). In 2004, the Conventional District drilled 23 gross (20.9 net) wells resulting in four gross (4 net) oil wells, 14 gross (12.4 net) gas wells and five gross (4.5 net) dry and abandoned wells for a success rate of 78 percent. The Company undeveloped lands in the Conventional district were 453,055 net acres at year-end 2004. During 2004, property acquisitions at Garden Plains, Turin and Stoddart were added to the Conventional District.

Acquisitions during 2004 significantly enhanced operations and prospects in the Conventional Oil and Gas District

STODDART – BRITISH COLUMBIA

The Stoddard asset acquisition was closed on December 22, 2004. Oil and liquids rich gas production from this largely year-round-access area comes from the Doig, Halfway, Baldonnal, Coplin and Bluesky formations. Oil is treated at two Company-operated batteries. Natural gas is compressed at four company-operated sites and sent for further processing at the outside-operated West Stoddard and Taylor Younger plants. Year-end 2004 production was approximately 10 mmcf/d of natural gas and 1,700 barrels per day of hydrocarbon liquids (3,400 boe per day). The Company plans to drill approximately four wells and recomplete up to seven wells in 2005 in the Stoddard area. Company net undeveloped lands were 25,343 acres at December 31, 2004.

GARDEN PLAINS/SEDALIA – ALBERTA

In 2001, Baytex acquired its initial position in this area and significantly increased its presence with a 2004 acquisition of a private company. December 2004 gas production was approximately 10 mmcf/d (1,700 boe per day). This area has the advantage of year-round access and multi-zone potential (Second White Specks, Viking and Mannville). Most of the gas production is processed by two Company-operated gas plants. The Company plans to drill four wells during 2005 in this area. Company net undeveloped lands were 77,498 acres at year-end 2004.

TURIN – ALBERTA

This multi-zone, year-round access property was acquired in 2004. December 2004 production was approximately two mmcf/d of natural gas and 900 barrels per day liquids (1,200 boe per day). Production comes from the Second White Specks, Milk River, Bow Island, Mannville, Sawtooth and Livingstone formations. Oil production is treated at three Company-operated batteries and gas is processed at two outside-operated gas plants. The Company plans to drill approximately five wells and recomplete up to 10 other wells during 2005 in the Turin area. Company net undeveloped lands were 31,335 acres at December 31, 2004.

RED EARTH/GOODFISH – ALBERTA

This winter-access, multi-zone property was acquired by Baytex in 1997. Relatively shallow decline oil production from Granite Wash and Slave Point pools is treated at two Company-operated sweet oil batteries. Natural gas production from the Bluesky formation is handled at two gas plants, one of which is Company-operated. Production during 2004 from this area averaged approximately eight mmcf/d of natural gas and 1,000 barrels per day hydrocarbon liquids (2,300 boe per day). In 2004, Baytex drilled eight net wells in 2004 resulting in four oil wells, two gas wells and two abandoned wells and plans to drill one well during 2005. Company net undeveloped lands were 44,448 acres at year-end 2004.

BON ACCORD – ALBERTA

This multi-zone property was acquired by Baytex in 1997. Production is from the Belly River, Viking and Mannville formations and averaged approximately six mmcf/d of gas and 300 barrels per day of hydrocarbon liquids (1,300 boe per day) in 2004. Natural gas is processed at two Company-operated plants and oil is treated at three Company-operated batteries. In late 2004, Baytex drilled two gas wells (1.5 net) which will be put on production in 2005, and plans to drill one well during 2005. Company net undeveloped lands were 47,725 acres at year-end 2004.

LEAHURST – ALBERTA

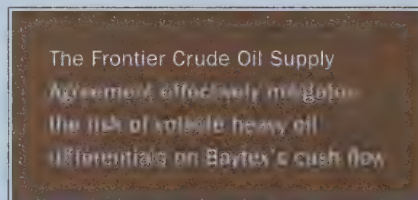
Production averaged approximately eight mmcf/d (1,300 boe per day) in 2004 from this multi-zone, year-round access area. Natural gas from the Edmonton, Belly River, Viking and Mannville formations is processed at several plants, one of which is Company-operated. In 2004, Baytex drilled five Mannville natural gas wells resulting in three gas wells and two abandonments. Baytex also successfully recompleted nine wells for coal-bed methane production from the Horseshoe Canyon coals during 2004. In 2005, Baytex plans to drill approximately 15 wells and recomplate seven wells in the Leahurst area. Company net undeveloped lands were 35,310 acres at year-end 2004.

NINA/DARWIN – ALBERTA

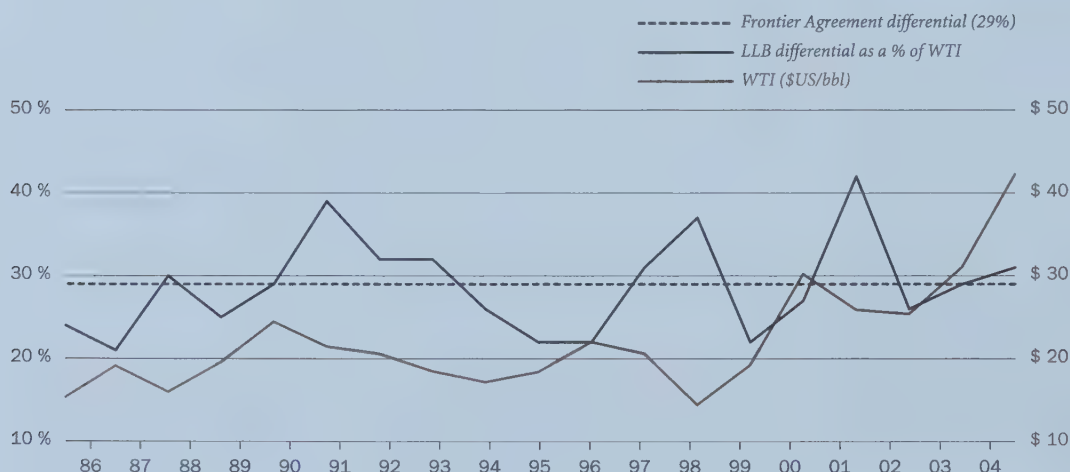
Both properties in this winter-access area produce natural gas from the Bluesky formation. Natural gas production is processed at two Company-operated gas plants. Production during 2004 averaged approximately five mmcf/d (800 boe per day). Six net wells were drilled in 2004 resulting in three producing gas wells. Company net undeveloped lands were 46,203 acres at year-end 2004.

HEAVY OIL SUPPLY AGREEMENT

In October 2002, Baytex signed a five-year crude oil supply agreement with Frontier Oil and Refining Company ("Frontier") of Houston, Texas. The agreement calls for Baytex to deliver 20,000 barrels per day of Lloyd Blend ("LLB") quality crude at Hardisty, Alberta through the Express Pipeline to Guernsey, Wyoming. The blended crude is comprised of approximately 15,500 barrels of Baytex production and 4,500 barrels per day of diluent. Prices are fixed at 71 percent of WTI or a 29 percent LLB differential which represents the long-term average differential since 1986. This contract significantly reduces the volatility of Baytex's cash flow from its heavy oil production.



HISTORY OF WTI AND DIFFERENTIALS



MARKETING

CRUDE OIL

World crude oil prices reached unprecedented levels in 2004 as strong Asian demand, uncertainty over Middle East supplies, hurricane-inflicted damage to U.S. Gulf of Mexico production facilities and diminishing excess OPEC productive capacity all contributed to record prices. Benchmark West Texas Intermediate (WTI) prices, after reaching an all-time high of US\$55.17 per barrel in late October, averaged \$41.40 in 2004, an increase of 33 percent from the 2003 average of \$31.04. The five-year average is \$30.92.

Canadian crude oil prices, while enjoying the strength in world prices, were tempered by the rising Canadian dollar against its U.S. counterpart. Canadian Par crude at Edmonton averaged \$52.57 per barrel in 2004, up 22 percent from \$43.16 in 2003. The five-year average is \$43.82.

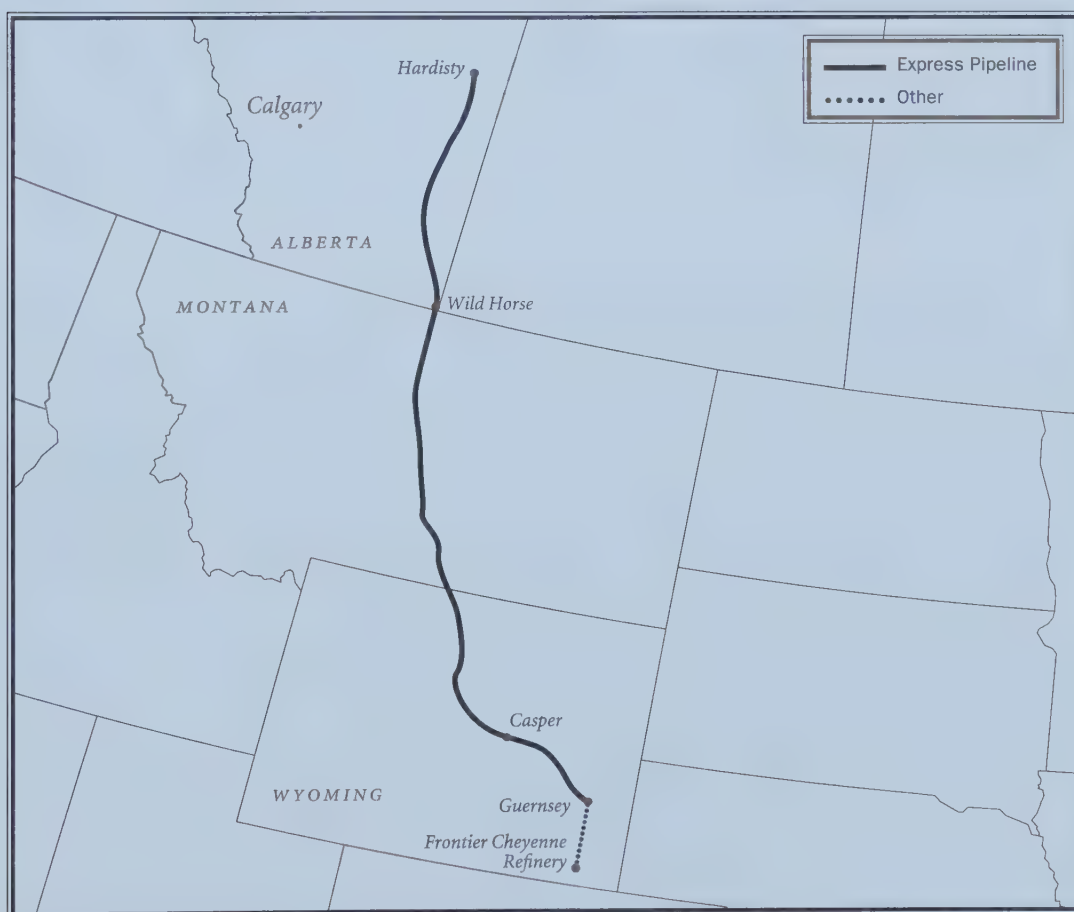
Baytex's conventional crude oil and natural gas liquids prices averaged \$48.64 per barrel in 2004 compared to \$40.01 in 2003.

With OPEC increasing oil output late in 2004 to meet surging world demand, supplies of heavy and sour crude oil grades increased and prices versus benchmark light sweet prices deteriorated. Canadian heavy oil prices were affected by this increased supply as the differential between WTI and Lloyd blend prices in Alberta averaged US\$14.01 per barrel in 2004 (34 percent of WTI) compared to US\$8.88 in 2003 (29 percent of WTI), with five-years averages at US\$9.68 and 31 percent.

Baytex's heavy oil prices averaged \$30.32 per barrel in 2004, compared to \$26.68 in 2003.

EXPRESS PIPELINE

Baytex's heavy crude oil is shipped to the Frontier Refinery in Cheyenne, Wyoming via the Express Pipeline system.



NATURAL GAS

Natural gas prices in North America were strong in 2004, reflecting high oil prices and concerns over gas supplies. U.S. gas prices, represented by the NYMEX futures contract, averaged US\$6.09 per thousand cubic feet (mcf) in 2004, an increase of 12 percent from \$5.44 in 2003. Daily prices for Alberta gas delivered to the AECO "C" trading hub averaged \$6.53/mcf in 2004 compared to \$6.66 in 2003, due to the impact of the strong Canadian dollar. Five-year average prices are US\$4.62 for the NYMEX contract, and \$5.71 for Alberta daily prices.

Baytex received an average of \$6.46 per mcf for 2004 natural gas sales compared to \$6.23 in 2003.

PRODUCTION

The Trust's average production for fiscal 2004 decreased by seven percent to 34,022 boe per day from 36,686 boe per day for fiscal 2003 due to asset dispositions and the transfer of properties pursuant to the Plan of Arrangement.

Light oil production decreased four percent to 2,172 barrels per day during 2004 from 2,273 barrels per day in 2003. Heavy oil production during 2004 was 22,703 barrels per day, a decrease of five percent from production of 23,911 barrels per day during 2003. Natural gas production for 2004 decreased by 13 percent to 54.9 mmcf/d compared to 63.0 mmcf/d for the prior year.

PRODUCTION BY AREA

	Light Oil and NGLs (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (mmcf/d)	Barrels of Oil Equivalent (boe/d)
2004				
Heavy Oil District	–	22,703	8.9	24,177
Conventional Oil and Gas District	2,172	–	46.0	9,845
Total Production	2,172	22,703	54.9	34,022
2003				
Heavy Oil District	–	23,911	10.6	25,676
Conventional Oil and Gas District	2,273	–	52.4	11,010
Total Production	2,273	23,911	63.0	36,686

REVENUE

Petroleum and natural gas sales for 2004 increased by four percent to \$420.4 million from \$403.0 million for fiscal 2003. Benchmark WTI crude oil averaged US\$41.40 per barrel for 2004, representing a 33 percent increase over the US\$31.04 per barrel for 2003. However, the Trust's realized wellhead prices were reduced by a strengthening Canadian dollar, which averaged US\$0.7683 in 2004 compared to US\$0.7135 in 2003. The Trust's light oil and NGLs price increased to \$48.64 per barrel from \$40.01 per barrel. The heavy oil price increased 14 percent to \$30.32 per barrel in 2004 from \$26.68 per barrel in 2003. Natural gas prices were four percent higher in 2004, averaging \$6.46 per mcf compared to \$6.23 per mcf during the previous year. Overall, after accounting for \$78.1 million of realized losses on financial derivative contracts, the Trust averaged \$27.48 per boe for 2004, a two percent decrease from \$28.07 per boe received in the prior year. For the per-sales-unit calculations, heavy oil sales for 2004 were five barrels per day lower (2003 – 650 barrels per day lower) than the production for the year due to inventory in transit under the Frontier supply agreement.

Restrictive oil hedges expired
at the end of 2004

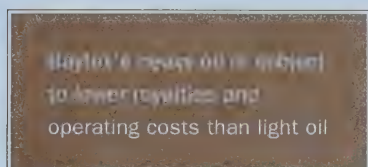
For 2004, light oil revenue increased 16 percent over 2003, due to a 22 percent increase in wellhead prices and a four percent decrease in production. Revenue from heavy oil increased 11 percent due to a five percent decrease in sales volume and a 14 percent increase in wellhead prices. Natural gas revenue decreased 10 percent as the 13 percent production decrease was offset by a four percent increase in wellhead price.

GROSS REVENUE ANALYSIS

	2004		2003	
	\$ thousands	\$/Unit ⁽¹⁾	\$ thousands	\$/Unit ⁽¹⁾
Oil revenue (barrels)				
Light oil	38,673	48.64	33,197	40.01
Heavy oil	252,016	30.32	226,482	26.68
Derivative contract loss	(78,124)	(8.58)	(33,777)	(3.62)
Total oil revenue	212,565	23.34	225,902	24.24
Natural gas revenue (mcf)	129,711	6.46	143,343	6.23
Total revenue (boe @ 6:1)	342,276	27.48	369,245	28.07

(1) Per-unit oil revenue is in \$/bbl; per unit natural gas revenue is in \$/mcf.

ROYALTIES



For the year ended December 31, 2004, royalties decreased to \$66.0 million from \$67.2 million for last year and were 15.7 percent of sales compared to 16.7 percent of sales in 2003. Royalties for 2004 were 14.1 percent of sales for light oil, 13.3 percent for heavy oil and 20.9 percent for natural gas. These rates compared to 17.4 percent, 13.0 percent and 22.3 percent, respectively, for 2003.

OPERATING EXPENSES

Operating expenses for 2004 increased five percent to \$89.1 million from \$86.0 million for 2003. This increase is attributable to general industry inflation. Operating expenses were \$7.15 per boe for 2004 compared to \$6.54 per boe for the prior year. In 2004, operating expenses were \$9.51 per barrel of light oil, \$7.83 per barrel of heavy oil and \$0.82 per mcf of natural gas compared to \$8.32, \$7.34 and \$0.73, respectively, for 2003.

TRANSPORTATION EXPENSES

Transportation expenses for 2004 were \$18.7 million compared to \$17.8 million for 2003. These expenses were \$1.50 per boe in 2004 compared to \$1.36 in 2003. Transportation expenses were \$1.66 per barrel of oil and \$0.18 per mcf of natural gas in 2004 and \$1.50 per barrel of oil and \$0.16 per mcf of natural gas in 2003.

OPERATING NETBACKS

	Light oil and NGLs		Heavy Oil		Total Oil and NGLs		Natural Gas		BOE	
	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003
Sales price	48.64	40.01	30.32	26.68	31.91	27.86	6.46	6.23	33.75	30.64
Royalties	(6.88)	(6.96)	(4.02)	(3.47)	(4.27)	(3.78)	(1.35)	(1.39)	(5.30)	(5.11)
Operating costs	(9.51)	(8.32)	(7.83)	(7.34)	(7.97)	(7.43)	(0.82)	(0.73)	(7.15)	(6.54)
Transportation	(0.92)	(0.97)	(1.73)	(1.55)	(1.66)	(1.50)	(0.18)	(0.16)	(1.50)	(1.36)
Net revenue	31.33	23.76	16.74	14.32	18.01	15.15	4.11	3.95	19.80	17.63

Note: Sales prices in this table are before the loss/gain recognized on financial derivative contracts.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses for the year were \$15.2 million compared to \$8.9 million for the prior year. On a per sales unit basis, these expenses were \$1.22 per boe in 2004 and \$0.71 per boe in 2003. In accordance with full cost accounting policy, \$4.4 million of expenses were capitalized in 2003, while no expenses have been capitalized in 2004. The amount of capitalized expenses has been reduced due to lower exploration activity since the effective date of the Plan of Arrangement.

Baytex's G&A expenses were on a unit basis \$1.22 per boe in 2004

GENERAL AND ADMINISTRATIVE EXPENSES

(\$ thousands)	2004	2003
Gross corporate expense	20,413	20,496
Operator's recoveries	(5,170)	(7,166)
Subtotal	15,243	13,330
Capitalized expense	-	(4,403)
Net expense	15,243	8,927

UNIT BASED COMPENSATION EXPENSE

The Trust accounts for compensation expense based on the fair value of rights granted under its unit-based compensation plan. The Trust is unable to determine the fair value of the rights granted as the plan contains a provision for the reduction, in certain circumstances, in the exercise price. Therefore, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the financial statements for unexercised rights. For 2004, compensation expense was \$7.7 million compared to \$0.7 million for 2003. Compensation expense on the Trust's unit rights incentive plan has been determined based on the amount that the market price of the trust unit exceeds the exercise price for rights issued as at the date of the consolidated financial statements. The compensation expense for 2003 also includes \$0.5 million based on the fair value of the stock options outstanding prior to the Plan of Arrangement

INTEREST EXPENSE

In 2004, interest expense was \$19.4 million for the year compared to \$23.5 million last year. The decrease in total interest expense is due to the redemption of the Company's senior secured notes in May 2003 and the stronger Canadian currency as interest on the long-term notes is denominated in U.S. dollars.

COSTS ON REDEMPTION AND EXCHANGE OF NOTES

On July 9, 2003, the Company completed an exchange offer related to its previously outstanding US\$150 million 10.5 percent senior subordinated notes due 2011 (the "Old Notes"). The Company issued US\$179.7 million of 9.625 percent senior subordinated notes due 2010 in exchange for US\$149.8 million of the Old Notes and incurred a non-cash loss of \$40.0 million on the completion of this transaction, which was recognized in income. Also recognized in income is \$4.7 million of costs on the redemption of the US\$57 million 7.23 percent senior secured notes.

FOREIGN EXCHANGE

The foreign exchange gain for 2004 was \$16.0 million compared to a gain of \$52.1 million in the prior year. The 2004 gain is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.8308 at December 31, 2004 compared to 0.7737 at December 31, 2003. The 2003 gain is based on translation at 0.7737 at December 31, 2003 compared to 0.6331 at December 31, 2002.

Baytex's U.S. dollar denominated long term debt provides a natural hedge against an appreciating Canadian dollar

DEPLETION, DEPRECIATION AND ACCRETION

Depletion, depreciation and accretion increased to \$160.8 million for 2004 compared to \$123.1 million for the same period last year. On a sales-unit basis, the depletion and depreciation provision for the current period was \$12.91 per boe compared to \$9.36 per boe for the same period a year earlier. This rate increase is due to the revisions in proved reserves at year-end 2003 pursuant to the implementation of the new standards of disclosure for oil and gas activities, National Instrument ("NI") 51-101.

INCOME TAXES

Current tax expenses were \$9.0 million for 2004 compared to \$9.7 million for the same period last year. The current tax expense is comprised of \$7.0 million of Saskatchewan Capital Tax and \$2.0 million of Large Corporation Tax compared to \$8.0 million and \$1.7 million, respectively, in 2003.

The fiscal 2004 provision for future income taxes was a recovery of \$41.2 million compared to a recovery of \$14.5 million for the prior year. The future income tax recovery for 2004 included a non-recurring adjustment resulting from a 0.5 percent decrease to the Alberta corporate income tax rate and from the federal legislation introduced to change the taxation of resource income.

CANADIAN TAX POOLS

(\$ thousands)	December 31, 2004
Cumulative Canadian Exploration Expense	1,283
Cumulative Canadian Development Expense	99,741
Cumulative Canadian Oil and Gas Property Expense	155,930
Undepreciated Capital Cost	195,235
Other	39,430
	<u>491,619</u>

CASH FLOW FROM OPERATIONS

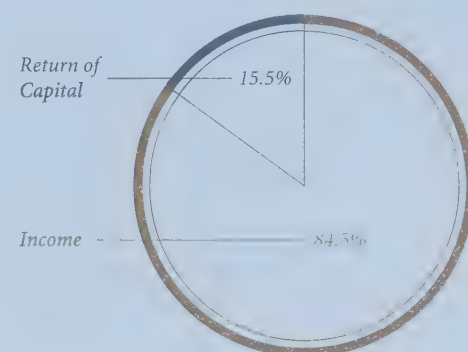
Cash flow from operations 2004 decreased 1.6 percent to \$136.0 million from \$138.2 million for the previous year. On a barrel of oil equivalent basis, cash flow from operations was \$10.03 for 2004 compared to \$10.40 for 2003. The decrease is due to higher realized losses from financial derivative contracts in 2004.

CASH FLOW NETBACKS

	2004		2003	
	\$/boe	Percent	\$/boe	Percent
Production revenue	33.75	100	30.64	100
Derivative contract loss	(6.27)	(19)	(2.57)	(8)
Royalties	(5.30)	(16)	(5.11)	(17)
Operating expenses	(7.15)	(21)	(6.54)	(21)
Transportation	(1.50)	(4)	(1.36)	(5)
Field netbacks	13.53	40	15.06	49
General and administrative expenses	(1.22)	(4)	(0.71)	(2)
Reorganization costs	-	-	(1.43)	(5)
Interest expense	(1.56)	(4)	(1.79)	(6)
Current income taxes	(0.72)	(2)	(0.73)	(2)
Cash flow netbacks	10.03	30	10.40	34

DISTRIBUTIONS

Baytex's 2004 distributions are 84.5% income and 15.5% return of capital



NET INCOME

Net income for 2004 was \$13.8 million compared to \$35.8 million for 2003. The increased petroleum and natural gas sales realized through higher wellhead prices in 2004 were offset by increased charges for depletion, depreciation and accretion, a lower foreign exchange gain and a higher realized loss on financial derivatives. Net income for each year has also been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income.

CAPITAL EXPENDITURES

Exploration and development expenditures decreased to \$94.5 million for 2004 compared to \$179.2 million last year. The lower capital expenditures reflect a different business plan since the conversion to an income trust. For the year ended December 31, 2004, the Trust participated in the drilling of 138 (135.0 net) wells, resulting in 104 (103.1 net) oil wells, 16 (14.4 net) gas wells, seven (6.5 net) stratigraphic test wells and 11 (11.0 net) dry holes compared to prior year activities of 266 (243.4 net) wells, including 173 (158.9 net) oil wells, 67 (61.4 net) gas wells, seven (5.1 net) service wells and 19 (18.0 net) dry holes. On September 22, 2004, the Company acquired all of the issued and outstanding shares of a private oil and gas company with operations in Alberta for \$109 million plus adjustments. Effective December 22, 2004, the Company acquired oil and natural gas interests in the West Stoddart area of northeast British Columbia for \$90 million plus adjustments.

Year Ended December 31

(\$ thousands)

	2004	2003
Land	8,744	14,138
Seismic	1,283	5,436
Drilling and completion	55,322	110,892
Equipment	25,982	42,365
Other	3,152	6,401
Total exploration and development	94,483	179,232
Corporate acquisition	111,042	—
Property acquisitions	89,582	6,644
Property dispositions	(14,441)	(137,493)
Total capital expenditures	280,666	48,383

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2004, total net debt (including working capital) was \$422.0 million compared to \$213.6 million at December 31, 2003. The \$422.0 million net debt included \$9.5 million of notional liabilities based on the mark-to-market valuations of derivative contracts as at December 31, 2004. The increase in total debt at year-end 2004 compared to 2003 was the result of the increase in bank loans used to fund capital expenditures during 2004.

Bavtex has access to diversified sources of capital to help minimize dilution to unitholders

The Company's debt structure consists of two components. The first component is the senior credit facilities. The Company has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances under the credit facilities or letters of credit can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The facilities aggregating \$250 million are subject to semi-annual review and are secured by a floating charge over all of the Company's assets. At December 31, 2004 a total of \$161.4 million had been drawn under the credit facilities.

The second component is the senior subordinated notes. On February 12, 2001, the Company issued US\$150 million of senior subordinated term notes ("Old Notes") bearing interest at 10.5 percent payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and

are subordinate to the Company's bank credit facilities. On July 9, 2003, the Company completed an exchange offer related to its Old Notes. The Company issued US\$179.7 million (\$247.1 million) of 9.625 percent senior subordinated notes due July 15, 2010 ("New Notes") in exchange for US\$149.8 million of the Old Notes. The New Notes are unsecured and are subordinate to the Company's bank credit facilities.

The bank credit facilities contain restrictions on the Company's ability to make distributions to the Trust if the Company is in default under such facilities or the distribution would have a material adverse effect on the ability of the Company to meet its obligations to its lenders. In addition, the note indenture relating to the senior subordinated notes contains a limitation on restricted payments whereby the Company is restricted from making any restricted payments, including distributions to the Trust, if a default or event of default under the note indenture has occurred and is continuing.

The Trust believes that cash flow generated from its operations, together with existing capacity under the bank facilities, will be sufficient to finance current operations and planned capital expenditures for the next year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments.

UNITHOLDERS' EQUITY

The Trust is authorized to issue an unlimited number of trust units. Pursuant to the Plan of Arrangement, 53.3 million trust units and 4.7 million exchangeable shares were issued on September 2, 2003 on the exchange of the common shares of the Company. An additional 6.5 million trust units were issued on December 12, 2003 for gross proceeds of \$65 million. On December 20, 2004, the Trust issued 3.6 million trust units at \$12.80 per unit for gross proceeds of \$46.1 million.

On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders can elect to reinvest monthly cash distributions in additional trust units of the Trust. Trust units purchased from treasury under the DRIP will be issued at a 5 percent discount from the weighted average closing price of the trust units on the Toronto Stock Exchange. The weighted average closing price is calculated as the weighted average trading price of trust units for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days. The Trust can also acquire trust units to be issued under the DRIP at prevailing market rates.

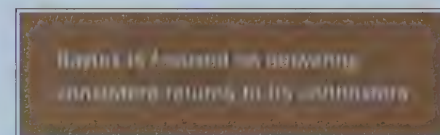
NON-CONTROLLING INTEREST

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either cash or the issue of trust units. At December 31, 2004, there were 1.9 million exchangeable shares outstanding. During 2004, a total of 1.8 million exchangeable shares were exchanged for trust units. The number of trust units issuable upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the weighted average trust unit price of the five-day trading period ending on the record date. The exchange ratio at December 31, 2004 was 1.21472 trust units per exchangeable share (December 31, 2003 – 1.04530 trust units per exchangeable share). Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the balance sheet.

CASH DISTRIBUTIONS

During 2004 total cash distributions of \$1.80 per unit were declared. The monthly cash distribution of \$0.15 per unit has been maintained since the inception of the Trust in September 2003.



OFF BALANCE SHEET ARRANGEMENTS AND CONTRACTUAL OBLIGATIONS

The Trust has assumed various contractual obligations and commitments, as detailed in the table below, in the normal course of operations and financing activities. These obligations and commitments have been considered when assessing the cash requirements in the above discussion of future liquidity.

CONTRACTUAL OBLIGATIONS

(\$ thousands)	Total	Payments Due by Period			
		Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt ⁽¹⁾	216,583	–	–	–	216,583
Operating leases	9,473	1,359	5,469	2,645	–
Capital lease	782	221	561	–	–
Transportation agreements	5,166	2,675	2,491	–	–
Total contractual obligations	232,004	4,255	8,521	2,645	216,583

(1) Total US \$180 million

The Trust also has ongoing obligations related to the abandonment and reclamation of well and facility sites which have reached the end of their economic lives. Programs to abandon and reclaim well and facility sites are undertaken regularly in accordance with applicable legislative requirements.

RISK AND RISK MANAGEMENT

The exploration for and the development, production and marketing of petroleum and natural gas involves a wide range of business and financial risks, some of which are beyond the Trust's control. Included in these risks are the uncertainty of finding new reserves, the fluctuations of commodity prices, the volatile nature of interest and foreign exchange rates, and the possibility of changes to royalty, tax and environmental regulations. The petroleum industry is highly competitive and the Trust competes with a number of other entities, many of which have greater financial and operating resources.

The business risks facing the Trust are mitigated in a number of ways. Geological, geophysical, engineering, environmental and financial analyses are performed on new exploration prospects, development projects and potential acquisitions to ensure a balance between risk and reward. The Trust's ability to increase its production, revenues and cash flow depends on its success in not only developing its existing properties but also in acquiring, exploring for and developing new reserves and production and managing those assets in an efficient manner.

Despite best practice analysis being conducted on all projects, there are numerous uncertainties inherent in estimating quantities of petroleum and natural gas reserves, including future oil and natural gas prices, engineering data, projected future rates of production and the timing of future expenditures. The process of estimating petroleum and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. An independent engineering firm evaluates the Trust's properties annually to determine a fair estimate of reserves. The Reserves Committee, consisting of independent members of the Company's Board of Directors, assists the Board in their annual review of the reserves evaluation.

The provision for depletion and depreciation in the financial statements and the ceiling test are based on reserves estimates. Any future significant revisions could result in a full cost accounting write-down or material changes to the annual rate of depletion and depreciation.

The financial risks that the Trust is exposed to as part of the normal course of its business are managed, in part, with various financial derivative instruments, in addition to fixed-price physical delivery contracts. The use of derivative instruments is governed under formal internal policies established by the Board of Directors. Derivative instruments are not used for speculative or trading purposes.

The Trust's financial results can be significantly affected by the prices received for petroleum and natural gas production as commodity prices fluctuate in response to changing market forces. This pricing volatility is expected to continue. As a result, The Trust has a risk management program that may be used to protect the prices of oil and natural gas on a portion of the total expected production. The objective is to decrease exposure to market volatility and ensure the Trust's ability to finance its distributions and capital program.

The Trust's financial results are also impacted by fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and, to a large extent, natural gas prices are based on reference prices denominated in U.S. dollars, while the majority of expenses are denominated in Canadian dollars. The exchange rate also impacts the valuation of the U.S. dollar denominated long-term notes. The related foreign exchange gains and losses are included in net income. There is no plan at this time to fix the exchange rate on any of the Trust's long-term borrowings.

The Trust is exposed to changes in interest rates as the Company's banking facilities are based on our lenders' prime lending rate and short-term Bankers' Acceptance rates. Changes in interest rates also impact the Company's interest rate swap contract which converts the fixed interest rate of 9.625 percent on the US\$179.7 million notes to a floating rate reset quarterly at the three month LIBOR rate plus 5.2 percent until the maturity of these notes.

The Trust's current position with respect to its financial derivative contracts is detailed in note 16 of the consolidated financial statements.

CRITICAL ACCOUNTING POLICIES

The preparation of the consolidated financial statements in accordance with generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. These critical estimates are discussed below.

OIL AND GAS ACCOUNTING

The Trust follows the full-cost accounting guideline to account for its petroleum and natural gas operations. Under this method, all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre. These capitalized costs, along with estimated future development costs, are depleted and depreciated on a unit-of-production basis using estimated proved petroleum and natural gas reserves. By their inclusion in the unit-of-production calculation, reserve estimates are a significant component of the calculation of depletion and depreciation and site restoration expense.

Independent engineers engaged by the Trust use all available geological, reservoir, and production performance data to prepare the reserve estimates. These estimates are reviewed and revised, either upward or downward, as new information becomes available. Revisions are necessary due to changes in assumptions based on reservoir performance, prices, economic conditions, government restrictions and other relevant factors. If reserve estimates are revised downward, net income could be affected by increased depletion and depreciation.

IMPAIRMENT OF PETROLEUM AND NATURAL GAS ASSETS

Companies that use the full-cost method of accounting for oil and natural gas operations are required to perform a ceiling test that calculates a limit for the net carrying cost of petroleum and natural gas assets. The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). The ceiling test is a two-stage process. The first stage of the test is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices. If reserve estimates are revised downward, net income could be affected by any additional depletion and depreciation recorded under the ceiling test calculation and could result a significant accounting loss for a particular period.

ASSET RETIREMENT OBLIGATIONS

The amounts recorded for asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

CHANGES IN ACCOUNTING POLICIES

UNIT-BASED COMPENSATION

At December 31, 2003, the Trust elected to adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" pursuant to the transitional provisions contained therein. Under this amended standard, the Trust accounts for compensation expense based on the fair value of rights granted under its unit-based compensation plan. As the Trust is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the consolidated financial statements for unexercised rights. For the year ended December 31, 2003, compensation expense of \$0.22 million was recorded as non cash general and administrative expense for all trust unit rights granted during 2003, with a corresponding amount recorded as contributed surplus.

The adoption of these amendments also impacted the stock options outstanding prior to the Plan of Arrangement. For the year ended December 31, 2003, compensation expense of \$0.52 million was recorded as non-cash general and administrative expense for all stock options granted on or after January 1, 2003, with a corresponding amount recorded as contributed surplus. For stock options granted prior to January 1, 2003, the pro forma earnings impact of related stock-based compensation expense is disclosed (note 18 to the consolidated financial statements).

FULL COST ACCOUNTING

In 2003, the CICA issued Accounting Guideline 16, Oil and Gas Accounting – Full Cost (AcG-16). The guideline is effective for fiscal years beginning on or after January 1, 2004. The new guideline modifies the ceiling test calculation applied by the Trust. The ceiling test was changed to a two-stage process which is to be performed at least annually. The first stage of the test is a recognition test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less

impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the carrying amount of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices. The adoption of this guideline on January 1, 2004 did not have an impact on the financial results of the Trust. The ceiling test impairment test was calculated on January 1, 2004 using the following benchmark reference prices at January 1, 2004 for the years 2004 to 2008 adjusted for commodity differentials specific to the Trust (note 17 to the consolidated financial statements):

	2004	2005	2006	2007	2008
WTI (\$US/bbl)	29.63	26.80	25.76	26.14	26.53
AECO (\$CDN/mcf)	6.03	5.36	4.80	4.91	4.98

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, the Trust adopted the CICA Section 3110, "Asset Retirement Obligations". This section requires recognition of a liability at discounted fair value for the future abandonment and reclamation associated with the petroleum and natural gas properties. The fair value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The related accretion expense is recognized in the statement of operations. The provision will be revised for any changes to timing related to cash flow or undiscounted abandonment costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligations to the extent that the liability exists on the balance sheet. Differences between the actual costs incurred and the fair value of the liability recorded are recognized in income in the period incurred.

The provisions of this section require that the standard be applied retroactively with restatement of comparative periods. As a result of this change, net income for the comparative year ended December 31, 2003 decreased by \$2.8 million, net of future income tax of \$0.8 million. At December 31, 2003 the asset retirement obligations balance increased by \$32.5 million to \$56.0 million, the petroleum and natural gas assets balance increased by \$19.2 million to \$862.3 million and the future tax liability decreased by \$5.0 million to \$169.3 million. The opening 2003 accumulated deficit increased by \$5.4 million (net of future income tax of \$0.8 million). There was no impact on cash flow from operations as a result of adopting this policy (note 8 to the consolidated financial statements).

FINANCIAL DERIVATIVE CONTRACTS

Effective January 1, 2004, the Trust implemented CICA Accounting Guideline 13 "Hedging Relationships" (AcG-13) for accounting for derivative contracts. This guideline addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue accrual accounting for positions hedged with derivatives. Upon implementation of AcG-13, Emerging Issues Committee Abstract 128 (EIC-128) also became effective. EIC-128 requires that changes in the fair value of these derivative contracts that do not qualify for hedge accounting under AcG-13 be recognized in the balance sheet and measured at fair value, with changes in fair value reported as income or expense in each reporting period. The income or expense relating to the change in fair value of the derivative contracts is an expense that has no impact on cash flow but may result in significant fluctuations in net income due to volatility in the underlying market prices. In accordance with the transitional provisions of AcG-13 and EIC-128, the new accounting treatment has been applied prospectively whereby prior periods have not been restated.

Prior to January 1, 2004, the Trust accounted for all derivative contracts whereby realized gains and losses on such contracts were included in the statement of operations within the corresponding item to which the contract was related. Following implementation of the guideline, realized and unrealized gains and losses on derivative contracts that do not qualify as effective hedges are reported separately in the statement of operations.

Pursuant to the transitional provisions contained in AcG-13, on January 1, 2004, the Trust recorded a deferred charge for the unrealized loss of \$10.1 million for the mark-to-market value of the outstanding non-hedging financial derivatives. This balance has been recognized in income during the year ended December 31, 2004. At December 31, 2004, the Trust recorded a liability of \$9.5 million on the mark-to-market value of the outstanding non-hedging financial derivatives. The change in the mark-to-market value of the non-hedging financial derivatives from the inception of the contracts to December 31, 2004 has been recorded as an unrealized gain on non-hedging financial derivatives of \$0.6 million in the consolidated statement of operations (note 16 to the consolidated financial statements).

TRANSPORTATION COSTS

CICA Handbook Section 1100, "Generally Accepted Accounting Principles", is effective for fiscal years beginning on or after October 1, 2003. This standard focuses on what constitutes Canadian generally accepted accounting principles and its sources, including the primary sources of generally accepted accounting principles. In prior periods, it had been industry practice to record revenue net of related transportation costs. In accordance with the new accounting standards, revenue is now reported before transportation costs with separate disclosure in the consolidated statement of operations of transportation costs. Petroleum and natural gas sales and transportation costs for the year ended December 31, 2004 both increased by \$18.7 million (2003 – \$17.8 million) as a result of this change. This change in classification has no impact on net income and the comparative figures have been restated to conform to the presentation adopted for the current period.

NON-CONTROLLING INTEREST

The Trust has implemented the accounting for the exchangeable shares issued by the Company as required by EIC Abstract 151, "Exchangeable Securities Issued by Subsidiaries of Income Trusts" (EIC 151), issued in January 2005. Under EIC 151, exchangeable shares issued by a subsidiary of an income trust are presented as non-controlling interest, unless certain conditions are met. The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary for them to be classified as equity. The presentation of the exchangeable shares at December 31, 2003 was restated to conform to the presentation for the current year, pursuant to the transitional provisions contained in EIC 151. Previously, the exchangeable shares were reflected as a component of Unitholders' Equity (note 10).

As a result of the adoption of EIC 151, net income was reduced in 2004 by \$0.35 million for the non-controlling interest's share of income and was increased in 2003 by \$0.67 million for the non-controlling interest's share of the loss from the date of the Arrangement. There was no impact on cash flow from operations as a result of adopting this policy. As the exchangeable shares are converted to Trust units, Unitholders' capital was increased by the fair value of the Trust units issued. The difference between the fair value of the Trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties.

The adoption of EIC 151 had the following impact on the Trust's previously reported financial statements:

(\$ thousands, except per unit amounts)	Three Months Ended				
	September 2004	June 2004	March 2004	December 2003	September 2003
Net income (loss)					
Previously reported: ⁽¹⁾	(12,604)	(11,170)	(4,296)	9,127	(46,245)
Restated:	(12,554)	(11,213)	(4,578)	8,490	(45,079)
Net income (loss) per unit basic					
Previously reported: ⁽¹⁾	(0.20)	(0.17)	(0.07)	0.14	(0.84)
Restated:	(0.20)	(0.18)	(0.07)	0.14	(0.82)
Net income (loss) per unit diluted					
Previously reported: ⁽¹⁾	(0.20)	(0.17)	(0.07)	0.14	(0.84)
Restated:	(0.20)	(0.18)	(0.07)	0.15	(0.84)

(\$ thousands, except per unit amounts)	Nine Months Ended September 2004	Six Months Ended June 2004	Year Ended December 2003	Nine Months Ended September 2003
Net income (loss)				
Previously reported: ⁽¹⁾	(28,070)	(15,466)	35,315	26,188
Restated:	(28,345)	(15,791)	35,844	27,354
Net income (loss) per unit basic				
Previously reported: ⁽¹⁾	(0.45)	(0.24)	0.64	0.48
Restated:	(0.45)	(0.25)	0.66	0.51
Net income (loss) per unit diluted				
Previously reported: ⁽¹⁾	(0.45)	(0.24)	0.62	0.48
Restated:	(0.45)	(0.25)	0.62	0.48

(\$ thousands, except per unit amounts)	As At				
	September 30, 2004	June 30, 2004	March 31, 2004	December 31, 2003	September 30, 2003
Unitholders' Equity					
Previously reported: ⁽¹⁾	325,292	362,791	400,492	431,210	385,678
Restated:	323,083	360,267	397,012	408,176	356,049
Non-controlling interest					
Previously reported:	—	—	—	—	—
Restated:	11,822	12,332	13,198	25,705	30,322

(1) The amounts previously reported as at and for the periods ended September 2003 and December 2003 have been restated for the adoption of the new accounting standard for asset retirement obligations.

NEW ACCOUNTING PRONOUNCEMENTS

FINANCIAL INSTRUMENTS

In January, 2005 the CICA issued three new standards relating to the reporting of financial instruments in financial statements. These standards introduce new requirements for the recognition and measurement of financial instruments and comprehensive income. Section 3855, "Financial Instruments – Recognition and Measurement" requires that all financial instruments, including derivatives, are to be included on a company's balance sheet and measured, either at their fair values or, in limited circumstances when fair value may not be considered most relevant, at cost or amortized cost. The standard also provides guidance on when gains and losses as a result of changes in fair values are to be recognized in the income statement.

The issuance of the new Section 3855 will result in amendments to Section 3860 "Financial Instruments – Disclosure and Presentation" to make the scope and definitions consistent with that of the new Section 3855, including expanding the scope to include certain commodity-based contracts, and to update certain disclosures in light of the introduction of Section 3855. Other Handbook Sections have also been amended for conformity with the new standards.

Section 3865 "Hedges", extends the existing requirements for hedge accounting currently under AcG -13. This new section allows for the optional treatment of accounting for financial instruments that are designated as either fair value hedges, cash flow hedges or hedges of a net investment in a self-sustaining foreign operation. For a fair value hedge, the gain or loss on a derivative hedging item, or the gain or loss on a non-derivative hedging item attributable to the hedged risk, is recognized in net income in the period of change together with the offsetting loss or gain on the hedged item attributable to the hedged risk. The carrying amount of the hedged item is adjusted for the hedged risk. For a cash flow hedge, the effective portion of the hedging item's gain or loss is initially reported in other comprehensive income and subsequently reclassified to net income when the hedged item affects net income. For a hedge of a net investment in a self-sustaining foreign operation the same accounting is followed as for a cash flow hedge.

A new location for recognizing certain gains and losses – other comprehensive income – has been introduced with the issued of Section 1530, "Comprehensive Income". An integral part of the accounting standards on recognition and measurement of financial instruments is the ability to present certain gains and losses outside net income, in other Comprehensive Income. This standard requires that a company should present comprehensive income and its components in a financial statement displayed with the same prominence as other financial statements that constitute a complete set of financial statements, in both annual and interim financial statements. Exchange gains and losses arising from the translation of the financial statements of a self-sustaining foreign operation, previously recognized in a separate component of shareholders' equity, in accordance with Section 1650, "Foreign Currency Translation", will now be recognized in a separate component of other comprehensive income.

These three new Handbook Sections are effective date for annual and interim periods in fiscal years beginning on or after October 1, 2006. The Trust is evaluating the impact the adoption of these new standards will have on its consolidated financial statements.

OTHER PROPOSED STANDARDS

The CICA has proposed amendments to Section 3500 "Earnings per Share", which include the requirement to include in the computation of basic earnings per share any shares issued upon conversion of a mandatorily convertible instrument. The computational guidance for calculating the number of incremental shares included in diluted shares when applying the treasury stock method

is also amended. These amendments were not enacted in final form as of the time of release of the Trust's 2004 consolidated financial statements.

The CICA has issued an Exposure Draft of a new Section 3830, "Non-Monetary Transactions" which proposes that all non-monetary transactions be measured at fair value, unless certain criteria are met. A final standard is planned to be issued in the first quarter of 2005.

A Re-Exposure draft on Section 3820, "Subsequent Events" was issued in January 2005, which proposes to separately define the subsequent event period and to require disclosure of the dates to which subsequent events are reflected in the financial statements. This Re-Exposure draft was not enacted in final form as of the time of release of the Trust's 2004 consolidated financial statements.

FOURTH QUARTER 2004

The following discussion reviews the Trust's results of operations for the fourth quarter of 2004.

Light oil production for the fourth quarter of 2004 increased by 41 percent to 2,786 barrels per day from 1,982 barrels per day a year earlier primarily due to the acquisition in September 2004. Heavy oil production decreased 8 percent to 22,490 barrels per day for the fourth quarter of 2004 compared to 24,400 barrels per day a year ago. Natural gas production decreased by 6 percent to 55.5 mmcf/d for the fourth quarter of 2004 compared to 58.9 mmcf/d for the same period last year. These decreases are due to a lower exploration and development program in 2004.

Petroleum and natural gas sales increased 24 percent to \$111.5 million for the quarter ended December 31, 2004 from \$89.5 million for the same period in 2003. Total royalties increased to \$17.4 million for the fourth quarter of 2004 from \$13.5 million in 2003. Total royalties for the fourth quarter of 2004 were 15.6 percent of sales compared to 15.1 percent of sales for the same period in 2003. Operating expenses for the fourth quarter of 2004 increased to \$24.2 million from \$22.1 million in the corresponding quarter last year. Operating expenses were \$7.63 per boe for the fourth quarter of 2004 compared to \$6.74 per boe for the fourth quarter of 2003. Transportation expenses for the fourth quarter of 2004 were \$4.6 million compared to \$4.7 million for the fourth quarter of 2003. These expenses were \$1.43 per boe for the fourth quarter of 2004 compared to \$1.45 for the same period in 2003.

General and administrative expenses increased to \$4.1 million in the fourth quarter of 2004 from \$3.6 million one year ago. On a per sales unit basis, these expenses were \$1.43 per boe for the fourth quarter of 2004 compared to \$1.21 per boe for 2003. In accordance with full cost accounting policy, no expenses were capitalized in either the fourth quarter of 2003 or 2004.

Interest expense increased to \$6.4 million for the fourth quarter of 2004 from \$5.2 million for the same quarter last year. The increase can be attributed to interest incurred on amounts drawn on the Trust's credit facilities in the fourth quarter of 2004.

The foreign exchange gain in the fourth quarter of 2004 was \$10.9 million compared to a gain of \$10.4 million in the prior year.

The provision for depletion, depreciation and accretion was \$41.5 million for the fourth quarter of 2004 compared to \$42.6 million for the same quarter a year ago. On a sales-unit basis, the provision for the current quarter was \$12.87 per boe compared to \$12.14 per boe for the same quarter in 2003.

Net income for the fourth quarter of 2004 was \$42.1 million compared to \$9.0 million for the corresponding quarter of 2003. In 2004, the increased petroleum and natural gas sales realized through higher wellhead prices in 2004 were offset by increased charges for depletion, depreciation and accretion, a lower foreign exchange gain and a higher realized loss on financial derivatives. In 2003, increased depletion expense was offset by foreign exchange gains and a recovery of future income taxes.

OUTSTANDING UNIT INFORMATION

At of February 28, 2005, the Trust had 66,650,987 units outstanding and the Company had 1,860,944 exchangeable shares outstanding. The exchange ratio at February 28, 2005 was 1.243 trust units per exchangeable share.

SELECTED ANNUAL INFORMATION

FINANCIAL (unaudited)

(\$ thousands, except per unit amounts)	2004	2003 ⁽²⁾	2002 ⁽²⁾
Revenue	420,400	403,022	372,037
Net income (loss) ⁽¹⁾	13,763	35,844	43,729
Per unit basic ⁽¹⁾	0.22	0.66	0.84
Per unit diluted ⁽¹⁾	0.21	0.62	0.82
Total assets	1,104,136	982,640	1,018,382
Total long-term financial liabilities	216,583	232,562	326,977
Cash distributions declared	113,063	33,382	—

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares. The net income and net income per unit for 2003 have been restated due to the retroactive application of the new accounting standard for non-controlling interest (see note 3 of the consolidated financial statements). The application of this standard did not impact the 2002 financial information.

(2) The financial information for 2003 and 2002 has been restated for the adoption of the new accounting standards related to asset retirement obligations and transportation expenses.

Overall production for 2004 was 34,022 boe per day which represented a seven percent decrease from 36,686 boe per day in 2003. Average wellhead prices received during 2004 were \$27.48 per boe compared to \$28.07 during 2003. Production in 2002 was 39,214 boe per day. Average wellhead prices received in 2002 were \$25.56 per boe. Total revenue for 2004 was \$420.4 million compared to \$403.0 million in 2003 and \$372.0 million in 2002.

QUARTERLY INFORMATION

	2004				2003			
(\$ thousands, except per share amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
FINANCIAL (unaudited)								
Revenue	111,521	108,216	104,517	96,146	89,526	98,692	89,999	124,805
Cash flow from operations	28,144	32,235	36,944	38,689	30,179	19,975	33,372	54,707
Per unit basic	0.44	0.51	0.59	0.63	0.51	0.36	0.62	1.03
Per unit diluted	0.42	0.49	0.57	0.60	0.51	0.36	0.61	1.01
Cash distribution declared	28,856	28,266	28,237	27,704	25,344	8,038	—	—
Per unit	0.45	0.45	0.45	0.45	0.45	0.15	—	—
Net income (loss) ⁽¹⁾	42,108	(12,554)	(11,213)	(4,578)	8,490	(45,079)	40,329	32,104
Per unit basic ⁽¹⁾	0.66	(0.20)	(0.18)	(0.07)	0.14	(0.82)	0.75	0.60
Per unit diluted ⁽¹⁾	0.65	(0.20)	(0.18)	(0.07)	0.14	(0.84)	0.73	0.59

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares. The net income and net income per unit for 2003 have been restated due to the retroactive application of the new accounting standard for non-controlling interest (see note 3 of the consolidated financial statements).

	2004				2003			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
<i>PRODUCTION</i>								
Conventional oil and NGLs (bbls/d)	2,786	1,890	1,952	2,058	1,982	1,989	2,167	2,969
Heavy oil (bbls/d)	22,490	22,083	22,927	23,322	24,400	25,123	22,816	23,278
Total oil and NGLs (bbls/d)	25,276	23,973	24,879	25,380	26,382	27,112	24,983	26,247
Natural gas (mmcf/d)	55.5	50.9	57.2	56.0	58.9	61.8	57.5	74.0
Barrels of oil equivalent (boe/d @ 6:1)	34,525	32,454	34,411	34,709	36,195	37,412	34,574	38,580
<i>AVERAGE PRICES</i>								
WTI oil (US\$/bbl)	48.28	43.88	38.32	35.15	31.18	30.20	28.91	33.86
Edmonton par oil (\$/bbl)	57.72	56.32	50.59	45.59	39.56	40.94	41.08	50.91
BTE light oil (\$/bbl)	50.46	52.63	47.55	43.50	37.46	35.40	38.24	46.21
BTE heavy oil (\$/bbl)	31.24	34.69	29.21	26.29	24.01	25.68	24.59	32.99
BTE total oil (\$/bbl)	33.35	36.11	30.63	27.70	25.04	26.39	25.80	34.57
BTE natural gas (\$/mcf)	6.60	6.16	6.61	6.43	5.56	5.79	6.21	7.17
BTE oil equivalent (\$/boe)	35.03	36.34	33.12	30.63	27.34	28.69	29.02	37.39

ADDITIONAL INFORMATION

Additional information relating to the Trust, including the Annual Information Form, may be found on SEDAR at www.sedar.com.

MANAGEMENT'S REPORT

Management, in accordance with Canadian generally accepted accounting principles, has prepared the accompanying consolidated financial statements of Baytex Energy Trust. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

Deloitte & Touche LLP were appointed by the Trust's unitholders to express an opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the independent auditors to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of the external auditors and reviews their fees. The external auditors have access to the Audit Committee without the presence of management.



RAYMOND T. CHAN, CA
President and Chief Executive Officer
Baytex Energy Ltd.



DANIEL G. BELOT
Vice President, Finance and Chief Financial Officer
Baytex Energy Ltd.

March 7, 2005

AUDITORS' REPORT

TO THE UNITHOLDERS OF BAYTEX ENERGY TRUST

We have audited the consolidated balance sheets of Baytex Energy Trust (the "Trust") as at December 31, 2004 and 2003 and the consolidated statements of operations and accumulated income (deficit) and cash flows for the years then ended. These consolidated financial statements are the responsibility of the management of the Trust. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

On March 7, 2005, we reported separately to the Trustee and Unitholders of Baytex Energy Trust on the consolidated financial statements for the same period, prepared in accordance with Canadian generally accepted accounting principles but which included Note 20, United States Accounting Principles and Reporting.



CALGARY, ALBERTA
March 7, 2005

CHARTERED ACCOUNTANTS

CONSOLIDATED BALANCE SHEETS

AS AT DECEMBER 31, 2004 AND 2003

(thousands)	2004	2003
		(restated – note 3)
ASSETS		
Current assets		
Cash and short-term investments	\$ –	\$ 53,731
Accounts receivable	41,154	48,608
Crude oil inventory	7,299	5,900
	48,453	108,239
Deferred charges and other assets	6,491	7,764
Petroleum and natural gas properties (note 5)	1,009,933	866,637
Goodwill (note 4)	39,259	–
	\$ 1,104,136	\$ 982,640
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	\$ 72,976	\$ 80,126
Distributions payable to unitholders	9,981	9,123
Bank loan (note 6)	161,444	–
Financial derivative contracts (note 16)	9,513	–
	253,914	89,249
Long-term debt (note 7)	216,583	232,562
Asset retirement obligation (note 8)	73,297	55,996
Future income taxes (note 13)	164,909	170,952
	708,703	548,759
Non-controlling interest (note 10)	12,962	25,705
UNITHOLDERS' EQUITY		
Unitholders' capital (note 9)	515,728	449,403
Contributed surplus	7,494	224
Accumulated distributions	(146,445)	(33,382)
Accumulated income (deficit)	5,694	(8,069)
	382,471	408,176
	\$ 1,104,136	\$ 982,640


Commitments and contingencies (note 17)

See accompanying notes to the consolidated financial statements.

On behalf of the Board



NAVEEN DARGAN
Director, Baytex Energy Ltd.



W. A. BLAKE CASSIDY
Director, Baytex Energy Ltd.

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED INCOME (DEFICIT)

YEARS ENDED DECEMBER 31, 2004 AND 2003

<i>(thousands, except per unit data)</i>	2004	2003
		<i>(restated - note 3)</i>
Revenue		
Petroleum and natural gas sales (note 3)	\$ 420,400	\$ 403,022
Royalties	(65,988)	(67,175)
Realized loss on financial derivatives	(78,124)	(33,777)
Unrealized gain on financial derivatives	597	-
	276,885	302,070
Expenses		
Operating	89,078	86,034
Transportation (note 3)	18,714	17,841
General and administrative	15,243	8,927
Unit based compensation (note 11)	7,736	739
Interest (note 7)	19,412	23,548
Costs on redemption and exchange of notes (note 7)	-	44,771
Foreign exchange gain (note 7)	(15,979)	(52,101)
Depletion, depreciation and accretion	160,808	123,137
Reorganization costs (note 18)	-	18,851
	295,012	271,747
Income (loss) before income taxes and non-controlling interest	(18,127)	30,323
Income taxes (recovery) (note 13)		
Current	9,000	9,663
Future	(41,237)	(14,516)
	(32,237)	(4,853)
Income before non-controlling interest	14,110	35,176
Non-controlling interest (note 10)	(347)	668
Net income	13,763	35,844
Accumulated deficit, beginning of year, as previously reported	(351)	(38,489)
Accounting policy change for non-controlling interest (note 3)	529	-
Accounting policy change for asset retirement obligations (note 3)	(8,247)	(5,424)
Accumulated deficit, beginning of year, as restated	(8,069)	(43,913)
Accumulated income (deficit), end of year	\$ 5,694	\$ (8,069)
Net income per trust unit (note 12)		
Basic	\$ 0.22	\$ 0.66
Diluted	\$ 0.21	\$ 0.62

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED DECEMBER 31, 2004 AND 2003

(thousands) 2004 2003
(restated – note 3)

CASH PROVIDED BY (USED IN):

OPERATING ACTIVITIES

Net income	\$ 13,763	\$ 35,844
Items not affecting cash:		
Unit based compensation (note 11)	7,736	739
Amortization of deferred charges	11,171	1,027
Costs on redemption and exchange of notes (note 7)	–	44,771
Unrealized foreign exchange gain	(15,979)	(52,101)
Depletion, depreciation and accretion	160,808	123,137
Unrealized gain on financial derivatives (note 16)	(597)	–
Future income taxes (recovery)	(41,237)	(14,516)
Non-controlling interest (note 10)	347	(668)
Cash flow from operations	136,012	138,233
Change in non-cash working capital (note 14)	3,589	(8,060)
Asset retirement expenditures	(2,739)	(880)
Decrease in deferred charges and other assets	212	211
Decrease in deferred credits	–	(2,213)
	137,074	127,291

FINANCING ACTIVITIES

Redemption of senior secured notes (note 7)	–	(89,950)
Increase in bank loan	161,444	–
Increase in deferred charges and other assets	–	(7,425)
Issue of trust units (note 9)	44,505	61,525
Payments of distributions	(112,074)	(24,259)
Issue of common shares (note 18)	–	37,049
	93,875	(23,060)

INVESTING ACTIVITIES

Petroleum and natural gas property expenditures	(184,065)	(185,876)
Corporate acquisition (note 4)	(111,042)	–
Disposal of petroleum and natural gas properties	14,441	137,493
Change in non-cash working capital (note 14)	(4,014)	(6,215)
	(284,680)	(54,598)

Change in cash and short-term

investments during the year	(53,731)	49,633
Cash and short-term investments, beginning of year	53,731	4,098
Cash and short-term investments, end of year	\$ –	\$ 53,731

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED DECEMBER 31, 2004 AND 2003

(all tabular amounts in thousands, except per unit amounts)

1. BASIS OF PRESENTATION

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement involving the Trust, Baytex Energy Ltd. (the "Company") and Crew Energy Inc. ("Crew"). The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, the Company is a wholly owned subsidiary of the Trust (note 18).

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of the Company and its subsidiaries and partnership. After giving effect to the Plan of Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor to the Company. The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles as described in note 2.

2. SIGNIFICANT ACCOUNTING POLICIES

CONSOLIDATION

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiaries from the respective dates of acquisition of the subsidiary companies. Inter-company transactions and balances are eliminated upon consolidation.

MEASUREMENT UNCERTAINTY

The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenues and expenses during the reporting period. Actual results can differ from those estimates.

In particular, amounts recorded for depreciation and depletion and amounts used for ceiling test calculations are based on estimates of petroleum and natural gas reserves and future costs required to develop those reserves. The Trust's reserve estimates are evaluated annually by an independent engineering firm. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

The amounts recorded for asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

CASH AND SHORT-TERM INVESTMENTS

Cash and short-term investments include monies on deposit and short-term investments, accounted for at cost, which have an initial maturity date of not more than 90 days.

CRUDE OIL INVENTORY

Crude oil inventory, consisting of production in transit in pipelines at the balance sheet date pursuant to a long-term crude oil supply agreement, is valued at the lower of cost or net realizable value.

PETROLEUM AND NATURAL GAS OPERATIONS

The Trust follows the full cost method of accounting for its petroleum and natural gas operations whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre and charged against income, as set out below. Such costs include land acquisition, drilling of productive and non-productive wells, geological and geophysical, production facilities, carrying costs directly related to unproved properties and corporate expenses directly related to acquisition, exploration and development activities and do not include any costs related to production or general overhead expenses. These costs along with estimated future capital costs that are based on current costs and that are incurred in developing proved reserves are depleted and depreciated on a unit of production basis using estimated proved petroleum and natural gas reserves, with both production and reserves stated before royalties. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs. Unproved properties are evaluated for impairment on an annual basis.

Gains or losses on the disposition of petroleum and natural gas properties are recognized only when crediting the proceeds to costs would result in a change of 20 percent or more in the depletion rate.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). The ceiling test is a two-stage process which is to be performed at least annually. The first stage of the test is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices. Any impairment is recorded as additional depletion and depreciation.

GOODWILL

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired business. Goodwill is stated at cost less impairment and is not amortized. The goodwill balance is assessed for impairment annually at year-end or more frequently if events or changes in circumstances indicate that the asset may be impaired. The test for impairment is conducted by the comparison of the net book value to the fair value of the reporting entity. If the fair value of the Trust is less than the net book value, impairment is deemed to have occurred. The extent of the impairment is measured by allocating the fair value of the Trust to the identifiable assets and liabilities at their fair values. Any remainder of this allocation is the implied value of goodwill. Any excess of the net book value of goodwill over this implied value is the impairment amount. Impairment is charged to income in the period in which it occurs.

ASSET RETIREMENT OBLIGATION

The Trust recognizes a liability at discounted fair value for the future abandonment and reclamation costs associated with the petroleum and natural gas properties. The fair value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The related accretion expense is recognized in the statement of operations. The provision will be revised for the effect of any changes to timing related to cash flow or undiscounted abandonment costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligations to the extent that the liability exists on the balance sheet. Differences between the actual costs incurred and the fair value of the liability recorded are recognized in income in the period the actual costs are incurred.

JOINT INTERESTS

A portion of the Trust's exploration, development and production activities is conducted jointly with others. These consolidated financial statements reflect only the Trust's proportionate interest in such activities.

FOREIGN CURRENCY TRANSLATION

Foreign currency denominated monetary items are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Exchange gains and losses on long-term monetary items that do not qualify for hedge accounting are recognized in income.

Revenue and expenses are translated at the monthly average rate of exchange. Translation gains and losses are included in net income.

DEFERRED CHARGES AND OTHER ASSETS

Financing costs related to the exchange of the senior subordinated notes have been deferred and are amortized over the term of the notes on a straight-line basis.

FINANCIAL DERIVATIVE CONTRACTS

The Trust formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The risk management policies included the permitted use of derivative financial instruments, including swaps and collars, used to manage these fluctuations. All transactions of this nature entered into by the Trust are related to an underlying financial instrument or to future petroleum and natural gas production. The Trust does not use financial derivatives for trading or speculative purposes. Financial derivative contracts used as hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue accrual accounting for positions hedged with financial derivative contracts. Financial derivative contracts that do not qualify for hedge accounting are recognized in the balance sheet and measured at fair value, with changes in fair value reported separately in the statement of operations as income or expense.

FUTURE INCOME TAXES

The Trust is a unit trust for income tax purposes, and is taxable on taxable income not allocated to the unitholders. From inception on September 2, 2003, the Trust has allocated all of its taxable income to the unitholders, and accordingly, no provision for income taxes is required at the Trust level.

The Company is subject to corporate income taxes and follows the liability method of accounting for income taxes. Income taxes are accounted for under the liability method of tax allocation, which determines future income taxes based on the differences between assets and liabilities reported for financial accounting purposes and those reported for tax purposes. Future income taxes are calculated using tax rates anticipated to apply in periods that temporary differences are expected to reverse.

FLOW-THROUGH SHARES

The Company had financed a portion of its exploration and development activities through the issue of flow-through shares. Under the terms of the flow-through share agreements, the tax attributes of the related expenditure are renounced to the subscribers. Accordingly, the book value of the expenditures incurred and the shares issued are recorded net of tax benefits renounced to the subscribers. The Company recorded the gross book value of the expenditures and a future tax liability for the tax benefits renounced to subscribers.

UNIT-BASED COMPENSATION

The Trust Unit Rights Incentive Plan is described in note 11. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. Therefore, it is not possible to determine a fair value for the rights granted under the Plan using a traditional option pricing model and compensation expense has been determined based on the intrinsic value of the rights at the date of exercise or at the date of the consolidated financial statements for unexercised rights.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase or decrease in contributed surplus. Changes in the intrinsic value of unexercised rights after the vesting period are recognized in income in the period of change with a corresponding increase or decrease in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

This method of determining compensation expense may result in large fluctuations, even recoveries, in compensation expense due to changes in the underlying trust unit price. Recoveries of compensation expense will only be recognized to the extent of previously recorded cumulative compensation expense associated with rights outstanding at the date of the financial statements.

NON-CONTROLLING INTEREST

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the consolidated balance sheet. As the exchangeable shares are converted to Trust units, the exchange is accounted for as a step-acquisition where Unitholders' capital was increased by the fair value of the Trust units issued. The difference between the fair value of the Trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties.

PER-UNIT AMOUNTS

Basic net income per unit is computed by dividing net income by the weighted average number of trust units outstanding during the year. Diluted per unit amounts reflect the potential dilution that could occur if trust unit rights were exercised or exchangeable shares were converted. The treasury stock method is used to determine the dilutive effect of trust unit rights, whereby any proceeds from the exercise of trust unit rights or other dilutive instruments and the amount of compensation expense, if any, attributed to future services and not yet recognized are assumed to be used to purchase trust units at the average market price during the period.

3. CHANGES IN ACCOUNTING POLICIES

UNIT-BASED COMPENSATION

At December 31, 2003, the Trust elected to adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" pursuant to the transitional provisions contained therein. Under this amended standard, the Trust accounts for compensation expense based on the fair value of rights granted under its unit-based compensation plan. As the Trust is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the consolidated financial statements for unexercised rights. For the year ended December 31, 2003, compensation expense of \$0.22 million was recorded for all trust unit rights granted during 2003, with a corresponding amount recorded as contributed surplus.

The adoption of these amendments also impacted the stock options outstanding prior to the Plan of Arrangement. For the year ended December 31, 2003, compensation expense of \$0.52 million was recorded as non-cash general and administrative expense for all stock options granted on or after January 1, 2003, with a corresponding amount recorded as contributed surplus. For stock options granted prior to January 1, 2003, the pro forma earnings impact of related stock-based compensation expense is disclosed (note 18).

FULL COST ACCOUNTING

In 2003, the CICA issued Accounting Guideline 16, Oil and Gas Accounting -- Full Cost (AcG-16). The guideline is effective for fiscal years beginning on or after January 1, 2004. The new guideline modifies the ceiling test calculation applied by the Trust. The ceiling test was changed to a two-stage process which is to be performed at least annually. The first stage of the test is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices. The adoption of this guideline on January 1, 2004 did not have an impact on the financial results of the Trust. The ceiling test impairment test was calculated on January 1, 2004 using the following benchmark reference prices at January 1, 2004 for the years 2004 to 2008 adjusted for commodity differentials specific to the Trust (note 17):

	2004	2005	2006	2007	2008
WTI (\$US/bbl)	29.63	26.80	25.76	26.14	26.53
AECO (\$CDN/mcf)	6.03	5.36	4.80	4.91	4.98

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, the Trust adopted the CICA Section 3110, "Asset Retirement Obligations". This section requires recognition of a liability at discounted fair value for the future abandonment and reclamation costs associated with the petroleum and natural gas properties. The fair value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The related accretion expense is recognized in the statement of operations. The provision will be revised for the effect of any changes to timing related to cash flow or undiscounted abandonment costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligations to the extent that the liability exists on the balance sheet. Differences between the actual costs incurred and the fair value of the liability recorded are recognized in income in the period in which the actual costs were incurred.

The provisions of this section require that the standard be applied retroactively with restatement of comparative periods. As a result of this change, net income for the comparative year ended December 31, 2003 decreased by \$2.8 million, net of future income tax of \$0.8 million. At December 31, 2003 the asset retirement obligations balance increased by \$32.5 million to \$56.0 million, the petroleum and natural gas assets balance increased by \$19.2 million to \$862.3 million and the future tax liability decreased by \$5.0 million to \$169.3 million. The opening 2003 accumulated deficit increased by \$5.4 million (net of future income tax of \$0.8 million). There was no impact on cash flow as a result of adopting this policy (note 8).

FINANCIAL DERIVATIVE CONTRACTS

Effective January 1, 2004, the Trust implemented CICA Accounting Guideline 13 "Hedging Relationships" (AcG-13) for accounting for derivative contracts. This guideline addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue accrual accounting for positions hedged with derivatives. Upon implementation of AcG-13, Emerging Issues Committee Abstract 128 (EIC-128) also became effective. EIC-128 requires that changes in the fair value of these derivative contracts that do not qualify for hedge accounting under AcG-13 be recognized in the consolidated balance sheet and measured at fair value, with changes in fair value reported as income or expense in each reporting period. The income or expense relating to the change in fair value of the derivative contracts is an expense that has no impact on cash flow but may result in significant fluctuations in net income due to volatility in the underlying market prices. In accordance with the transitional provisions of AcG-13 and EIC-128, the new accounting treatment has been applied prospectively whereby prior periods have not been restated.

Prior to January 1, 2004, the Trust accounted for all derivative contracts whereby realized gains and losses on such contracts were included in the statement of operations within the corresponding item to which the contract was related. Following implementation of the guideline, realized and unrealized gains and losses on derivative contracts that do not qualify as effective hedges are reported separately in the statement of operations.

Pursuant to the transitional provisions contained in AcG-13, on January 1, 2004, the Trust recorded a deferred charge for the unrealized loss of \$10.1 million for the mark-to-market value of the outstanding non-hedging financial derivatives. This balance has been recognized in income during the year ended December 31, 2004. At December 31, 2004, the Trust recorded a liability of \$9.5 million on the mark-to-market value of the outstanding non-hedging financial derivatives. The change in the mark-to-market value of the non-hedging financial derivatives from the inception of the contracts to December 31, 2004 has been recorded as an unrealized gain on non-hedging financial derivatives of \$0.6 million in the consolidated statement of operations (note 16).

TRANSPORTATION COSTS

CICA Handbook Section 1100, "Generally Accepted Accounting Principles", is effective for fiscal years beginning on or after October 1, 2003. This standard focuses on what constitutes Canadian generally accepted accounting principles and its sources, including the primary sources of generally accepted accounting principles. In prior periods, it had been industry practice to record revenue net of related transportation costs. In accordance with the new accounting standards, revenue is now reported before transportation costs with separate disclosure in the consolidated statement of operations of transportation costs. Petroleum and natural gas sales and transportation costs for the year ended December 31, 2004 both increased by \$18.7 million (2003 – \$17.8 million) as a result of this change. This change in classification has no impact on net income and the comparative figures have been restated to conform to the presentation adopted for the current period.

NON-CONTROLLING INTEREST

The Trust has implemented the accounting for the exchangeable shares issued by the Company as required by EIC Abstract 151, "Exchangeable Securities Issued by Subsidiaries of Income Trusts" (EIC 151), issued in January 2005. Under EIC 151, exchangeable shares issued by a subsidiary of an income trust are presented as non-controlling interest, unless certain conditions are met. The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. The presentation of the exchangeable shares at December 31, 2003 was restated to conform to the presentation for the current year, pursuant to the transitional provisions contained in EIC 151. Previously, the exchangeable shares were reflected as a component of Unitholders' Equity.

As a result of the adoption of EIC 151, net income was reduced in 2004 by \$0.35 million for the non-controlling interest's share of income and was increased in 2003 by \$0.67 million for the non-controlling interest's share of the loss from the date of the Arrangement. As the exchangeable shares are converted to Trust units, the exchange is accounted for as a step-acquisition where Unitholders' capital was increased by the fair value of the Trust units issued. The difference between the fair value of the Trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties. During the year ended December 31, 2004, the adoption of EIC 151 resulted in a \$15.0 million increase in petroleum and natural gas properties (December 2003 – \$4.3 million), a \$5.7 million increase in future income taxes (December 2003 – \$1.6 million) and a \$10.9 million increase in unitholders' capital (December 2003 – \$2.8 million).

4. CORPORATE ACQUISITION

Effective September 22, 2004, the Company acquired all of the issued and outstanding shares of a private oil and gas company with operations in Alberta. The transaction was accounted for using the purchase method of accounting. The estimated fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below. The Company has not yet completed its final valuation of the assets acquired and liabilities assumed and, therefore, the purchase price allocation may be subject to change. Subsequent to the acquisition, the private company was amalgamated with the Company.

Petroleum and natural gas properties	\$ 109,777
Goodwill	39,259
Working capital	1,447
Capital lease obligation	(777)
Asset retirement obligation	(8,435)
Future income taxes	(30,229)
Total net assets acquired	\$ 111,042
Financed by:	
Cash	\$ 110,822
Costs associated with acquisition	220
Total purchase price	\$ 111,042

Goodwill of \$39.3 million was determined based on the excess of the total consideration paid less the value assigned to the identifiable assets and liabilities including the future income tax liability.

5. PETROLEUM AND NATURAL GAS PROPERTIES

As at December 31,	2004	2003
		(restated – note 3)
Petroleum and natural gas properties	\$ 2,342,514	\$ 2,042,749
Accumulated depletion and depreciation	(1,332,581)	(1,176,112)
	\$ 1,009,933	\$ 866,637

In calculating the depletion and depreciation provision for 2004, \$61.7 million (2003 – \$51.1 million) of costs relating to undeveloped properties and materials and supplies of \$3.7 million (2003 – \$4.0 million) were excluded from costs subject to depletion and depreciation. During 2003, \$4.4 million of corporate expenses relating to exploration and development activities were capitalized. No corporate expenses have been capitalized since the inception of operations as a trust effective September 2, 2003.

The petroleum and natural gas properties are subject to a ceiling test, which was calculated at December 31, 2004 using the following benchmark reference prices for the years 2005 to 2009 adjusted for commodity differentials specific to the Trust (note 17):

	2005	2006	2007	2008	2009
WTI (\$US/bbl)	44.29	41.60	37.09	33.46	31.84
AECO (\$CDN/mcf)	6.97	6.66	6.21	5.73	5.37

The prices and costs subsequent to 2009 have been adjusted for inflation at an annual rate of 1.5 percent. Based on the ceiling test calculation, the Trust's estimated undiscounted future net cash flows associated with the proved and probable reserves exceeded the book value of the petroleum and natural gas properties.

6. BANK CREDIT FACILITIES

The Company has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances under the credit facilities or letters of credit (note 17) can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The facilities aggregating \$250 million are subject to semi-annual review and are secured by a floating charge over all of the Company's assets. At December 31, 2004 a total of \$161.4 million had been drawn under the credit facilities.

7. LONG-TERM DEBT

As at December 31,	2004	2003
10.5% senior subordinated notes (US\$247,000)	\$ 297	\$ 319
9.625% senior subordinated notes (US\$179,699,000)	216,286	232,243
	\$ 216,583	\$ 232,562

SENIOR SUBORDINATED NOTES

On February 12, 2001, the Company issued US\$150 million of senior subordinated notes ("Old Notes") bearing interest at 10.5 percent payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities.

On July 9, 2003, the Company completed an exchange offer related to its Old Notes. The Company issued US\$179.7 million of 9.625 percent senior subordinated notes due July 15, 2010 ("New Notes") in exchange for US\$149.8 million of the Old Notes and incurred a non-cash loss of \$40.0 million on the completion of this transaction, which was recognized in income. The New Notes are unsecured and are subordinate to the Company's bank credit facilities. In November 2003, the Company entered

into an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three month LIBOR rate plus 5.2 percent until the maturity of these notes.

SENIOR SECURED NOTES

On November 13, 1998, the Company issued US\$57 million of senior secured notes, bearing interest at 7.23 percent payable quarterly with principal repayable on November 13, 2004. In May 2003, the Company redeemed the outstanding senior secured notes for a total cash payment of \$90 million, resulting in a cost of \$4.7 million on the redemption.

INTEREST EXPENSE

The Company has incurred interest expense on its outstanding debt as follows:

	2004	2003
Bank loan	\$ 2,256	\$ 675
Amortization of deferred charges	1,060	1,027
Long-term debt	16,096	21,846
Total interest	\$ 19,412	\$ 23,548

8. ASSET RETIREMENT OBLIGATIONS

As at December 31,	2004	2003
		(restated - note 3)
Balance, beginning of the year	\$ 55,996	\$ 52,244
Liabilities incurred	4,623	4,010
Liabilities settled	(2,739)	(880)
Acquisition of liabilities	12,797	—
Disposition of liabilities	(1,722)	(3,335)
Accretion	4,342	3,957
Balance, end of the year	\$ 73,297	\$ 55,996

The Trust's asset retirement obligations are based on the Trust's net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 55 years with the majority of costs incurred between 2029 and 2060. The undiscounted amount of estimated cash flow required to settle the retirement obligations at December 31, 2004 is \$189 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0 percent and an inflation rate of 1.5 percent.

9. UNITHOLDERS' CAPITAL

TRUST UNITS

The Trust is authorized to issue an unlimited number of trust units. Pursuant to the Plan of Arrangement, 53,304,858 trust units and 4,732,326 exchangeable shares were issued on September 2, 2003 on the exchange of the common shares of the Company (notes 10 and 18).

On December 20, 2004, the Trust issued 3,600,000 trust units at \$12.80 per unit for gross proceeds of \$46.1 million pursuant to a prospectus. On December 12, 2003, the Trust issued 6,500,000 trust units at \$10.00 per unit for gross proceeds of \$65 million pursuant to a prospectus.

TRUST UNITS

	<i>Number of units</i>	<i>Amount</i>
Issued September 2, 2003 pursuant to		
Plan of Arrangement (note 18)	53,305	\$ 377,419
Issued on conversion of Exchangeable Shares	1,016	9,944
Unit-based compensation	–	515
Issued for cash, net of expenses	6,500	61,525
Balance December 31, 2003 (restated – note 3)	60,821	449,403
Issued on conversion of Exchangeable Shares	1,994	21,222
Issued on exercise of trust unit rights ⁽¹⁾	113	1,472
Issued pursuant to distribution reinvestment program	10	131
Issued for cash, net of expenses	3,600	43,500
Balance December 31, 2004	66,538	\$ 515,728

(1) Includes compensation expense transferred from contributed surplus.

On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. Trust units purchased from treasury under the DRIP will be issued at a 5 percent discount from the weighted average closing price of the trust units on the Toronto Stock Exchange. The weighted average closing price is calculated as the weighted average trading price of trust units for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days. The Trust can also acquire trust units to be issued under the DRIP at prevailing market rates.

10. NON-CONTROLLING INTEREST

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either cash or the issue of trust units. The number of trust units issued upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is adjusted monthly based on the cash distribution paid divided by the weighted average trust unit price of the five-day trading period ending on the record date. The exchange ratio at December 31, 2004 was 1.21472 trust units per exchangeable share (2003 – 1.04530 trust units per exchangeable share). Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase or decrease to the non-controlling interest on the balance sheet.

NON-CONTROLLING INTEREST

	Number of Exchangeable Shares	Amount
Issued September 2, 2003 pursuant to Plan of Arrangement (note 18)	4,732	\$ 33,507
Exchanged for trust units	(1,007)	(7,134)
Non-controlling interest in net income (loss)	–	(668)
Balance December 31, 2003 (restated – note 3)	3,725	25,705
Exchanged for trust units	(1,849)	(13,090)
Non-controlling interest in net income (loss)	–	347
Balance December 31, 2004	1,876	\$ 12,962

As the exchangeable shares are converted to Trust units, the exchange is accounted for as a step-acquisition where Unitholders' capital was increased by the fair value of the Trust units issued. The difference between the fair value of the Trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties. During the year ended December 31, 2004, the adoption of EIC 151 resulted in a \$15.0 million increase in petroleum and natural gas properties (December 2003 – \$4.3 million), a \$5.7 million increase in future income taxes (December 2003 – \$1.6 million) and a \$10.9 million increase in unitholders' capital (December 2003 – \$2.8 million).

11. TRUST UNIT RIGHTS

Effective September 2, 2003, the Trust established a Trust Unit Rights Incentive Plan to replace the stock option plan of the Company. A total of 5,800,000 Trust Unit Rights are reserved for issue under the Plan. Trust Unit Rights are granted at the market price of the trust units at the time of the grant, vest over three years and have a term of five years.

The Trust Unit Rights Incentive Plan allows for the exercise price of the rights to be reduced in future periods by a portion of the future distributions provided a certain threshold return on assets is met. The Trust has determined that the amount of the reduction cannot be reasonably estimated, as it is dependent upon a number of factors including, but not limited to, future trust unit prices, production of oil and natural gas, determination of amounts to be withheld from future distributions to fund capital expenditures, and the purchase and sale of oil and natural gas assets. Therefore, it is not possible to determine a fair value for the rights granted under the plan.

Compensation expense is therefore determined based on the amount that the market price of the trust unit exceeds the exercise price for rights issued as at the date of the consolidated financial statements. The accounting for unit-based compensation results in compensation expense for year ended December 31, 2004 of \$7.7 million (2003 – \$0.22 million).

The number of unit rights issued and exercise prices are detailed below:

	Number of Rights	Weighted average exercise price ⁽¹⁾
Initial grant September 9, 2003	2,593	\$ 10.23
Granted	380	\$ 9.60
Cancelled	(118)	\$ 10.23
Balance December 31, 2003	2,855	\$ 10.15
Granted	1,297	\$ 11.77
Exercised	(113)	\$ 8.87
Cancelled	(502)	\$ 9.54
Balance December 31, 2004	3,537	\$ 9.60

(1) Exercise price reflects grant price less reduction in exercise price as discussed above.

The following table summarizes information about the unit rights outstanding at December 31, 2004:

Range of Exercise Prices	Number Outstanding at December 31, 2004	Weighted Average Remaining Term (years)	Weighted Average Exercise Price	Number Exercisable at December 31, 2004	Weighted Average Exercise Price
\$7.21 to \$8.49	2,239	3.7	\$ 8.34	680	\$ 8.34
\$8.50 to \$9.99	176	4.1	\$ 9.12	—	—
\$10.00 to \$11.49	361	4.6	\$11.30	—	—
\$11.50 to \$13.25	761	4.9	\$12.60	—	—
\$7.21 to \$13.25	3,537	4.0	\$ 9.60	680	\$ 8.34

12. NET INCOME PER UNIT

The Trust applies the treasury stock method to assess the dilutive effect of outstanding trust unit rights on net income per unit. The weighted average exchangeable shares outstanding at year-end, converted at the year-end exchange ratio, have also been included in the calculation of the diluted weighted average number of trust units outstanding:

	2004	2003
Weighted average number of units outstanding, basic	62,574	53,995
Trust units issuable on conversion of exchangeable shares	2,635	1,535
Dilutive effect of trust unit incentive rights	473	990
Weighted average number of units outstanding, diluted	65,682	56,520

The dilutive effect of trust unit incentive rights above did not include 3.1 million trust unit rights (2003 – 2.7 million) because the respective exercise prices exceeded the average market price of the trust units during the year and the amount of compensation expense attributed to future services and not yet recognized.

13. INCOME TAXES (RECOVERY)

The provision for (recovery of) income taxes has been computed as follows:

	2004	2003
		(restated – note 3)
Income (loss) before income taxes and non-controlling interest	\$ (18,127)	\$ 30,323
Expected income taxes (recovery) at the statutory rate of 40.57% (2003 – 42.5%)	\$ (7,354)	\$ 12,887
Increase (decrease) in taxes resulting from:		
Crown royalties	18,802	21,451
Resource allowance	(9,663)	(18,334)
Alberta royalty tax credit	(203)	(213)
Net income of the Trust	(46,469)	(14,191)
Non-taxable portion of foreign exchange gain	(3,241)	(11,074)
Effect of change in tax rate	(10,324)	(5,462)
Effect of change in opening tax pool balances	8,711	—
Effect of change in valuation allowance	5,194	—
Unit based compensation	2,949	314
Other	361	106
Large corporation tax and provincial capital tax	9,000	9,663
Provision for (recovery of) income taxes	\$ (32,237)	\$ (4,853)

The components of future income taxes are as follows:

As at December 31,	2004	2003
		(restated – note 3)
Future income tax liabilities:		
Capital assets	\$ 193,584	\$ 209,425
Other	12,853	2,560
Future income tax assets:		
Asset retirement obligation	(26,072)	(21,239)
Reorganization costs	(12,206)	(19,794)
Loss carry-forward	(3,250)	–
Future income taxes	\$ 164,909	\$ 170,952

14. CASH FLOW INFORMATION

INCREASE (DECREASE) IN NON-CASH WORKING CAPITAL ITEMS

	2004	2003
Current assets	\$ 6,055	\$ (1,840)
Current liabilities	(5,630)	(12,435)
	\$ 425	\$ (14,275)
Changes in non cash working capital related to:		
Operating activities	\$ 3,589	\$ (8,060)
Investing activities	(4,014)	(6,215)
	\$ 425	\$ (14,275)

During the year the Trust made the following cash outlays in respect of interest expense and current income taxes.

	2004	2003
Interest	\$ 21,096	\$ 24,449
Current income taxes	\$ 17,485	\$ 12,557

15. FINANCIAL INSTRUMENTS

The Trust's financial instruments recognized in the balance sheet consist of cash and short-term investments, accounts receivable, current liabilities and long-term borrowings. The estimated fair values of the financial instruments have been determined based on the Trust's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction.

The fair values of financial instruments other than bank debt and long-term borrowings approximate their book amounts due to the short-term maturity of these instruments. The fair value of the bank debt approximates its book value as it is at a market rate of interest. At December 31, 2004, the trading value of the Company's senior subordinated term notes was 105 percent in relation to par (2003 – 105 percent).

Most of the Trust's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Trust manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. The book value of the accounts receivable reflects management's assessment of the associated credit risks.

16. FINANCIAL DERIVATIVE CONTRACTS

The nature of the Trust's operations results in exposure to fluctuations in commodity prices, exchange rates and interest rates. The Trust monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Trust is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts.

At December 31, 2004, the Trust had derivative contracts for the following:

<i>OIL</i>	<i>Period</i>	<i>Volume</i>	<i>Price</i>	<i>Index</i>
Price collar	Calendar 2005	3,000 bbls/d	US\$35.00 – \$42.40	WTI
Price collar	Calendar 2005	2,000 bbls/d	US\$35.00 – \$42.50	WTI
Price collar	Calendar 2005	1,000 bbls/d	US\$35.00 – \$42.70	WTI
Price collar	Calendar 2005	2,000 bbls/d	US\$35.00 – \$42.75	WTI

INTEREST RATE SWAP

<i>Period</i>	<i>Principal</i>	<i>Rate</i>
November 2003 to July 2010	US\$179,699,000	3-month LIBOR plus 5.2%

As discussed in note 3, under the new guideline for hedge accounting, the Trust's financial derivative contracts for oil collars do not qualify as effective accounting hedges. Accordingly, these contracts have been accounted for based on the fair value method. Pursuant to the transitional provisions contained in AcG-13, on January 1, 2004, the Trust recorded a deferred charge for the unrealized loss of \$10.1 million for the mark-to-market value of the outstanding non-hedging financial derivatives. This balance has been recognized in income during the year ended December 31, 2004. At December 31, 2004, the Trust recorded a liability of \$9.5 million on the mark-to-market value of the outstanding non-hedging financial derivatives. The change in the mark-to-market value of the non-hedging financial derivatives from the inception of the contracts to December 31, 2004 has been recorded as an unrealized gain on non-hedging financial derivatives of \$0.6 million in the consolidated statement of operations. The Trust is applying hedge accounting to the interest rate swap and gains and losses are netted against interest expense.

17. COMMITMENTS AND CONTINGENCIES

In October 2002, the Trust entered into a long-term crude oil supply contract with a third party that requires the delivery of up to 20,000 barrels per day of Lloydminster Blend crude oil at a price fixed at 71 percent of NYMEX WTI oil price. The contract is for an initial term of five years commencing January 1, 2003. The contract volumes increased from 9,000 barrels per day in January 2003 to 20,000 barrels per day in October 2003 and thereafter.

At December 31, 2004, there are outstanding letters of credit aggregating \$2.2 million issued as security for performance under certain contracts.

The Trust is engaged in litigation and claims arising in the normal course of operations, none of which could reasonably be expected to materially affect the Trust's financial position or reported results of operations.

18. TRANSFER OF ASSETS AND LIABILITIES PURSUANT TO PLAN OF ARRANGEMENT

Under the Plan of Arrangement (note 1), the Company transferred to Crew a portion of the Company's producing and exploratory petroleum and natural gas assets. As this was a related party transaction, assets and liabilities were transferred at net book value as follows:

Petroleum and natural gas assets and equipment	\$	21,244
Future income tax asset		3,278
Total assets transferred		24,522
Provision for future site restoration		(559)
Net assets transferred and reduction in share capital	\$	23,963

Reorganization costs of \$18.9 million were expensed in the consolidated statements of operations as a result of the Plan of Arrangement.

Under the Plan of Arrangement, shareholders of the Company received one unit of the Trust or one exchangeable share and one-third of a share of Crew for each common share held.

COMMON SHARES OF BAYTEX ENERGY LTD.

	Number of shares	Amount
Balance December 31, 2002	52,819	\$ 398,176
Flow-through shares issued	103	810
Future tax related to flow-through shares	—	(336)
Exercise of stock options	5,115	36,239
Transfer of assets under Plan of Arrangement	—	(23,963)
Balance September 2, 2003 prior to Plan of Arrangement	58,037	410,926
Trust units issued (note 9)	(53,305)	(377,419)
Exchangeable shares issued (note 10)	(4,732)	(33,507)
Balance December 31, 2003	—	\$ —

The Company had a stock option plan prior to the Plan of Arrangement. The outstanding stock options of the Company were exercised or cancelled as follows:

	Number of options	Weighted average exercise price
Balance December 31, 2002	5,126	\$ 6.98
Granted	121	\$ 9.28
Exercised	(5,115)	\$ 7.07
Cancelled	(132)	\$ 5.44
Balance December 31, 2003	—	—

The adoption of the amendments related to accounting for unit-based compensation also impacted the accounting for stock options granted by the Company to employees before the implementation of the Plan of Arrangement. Compensation expense of \$0.52 million was recorded for all stock options granted by the Company on or after January 1, 2003, with a corresponding amount recorded as trust units on exercise of the options, with expenses in the first and second quarters increased by \$0.32 million and \$0.20 million, respectively. Accordingly, quarterly net income in such quarters previously reported as \$32.9 million and \$41.8 million would be revised to \$32.6 million and \$41.6 million, respectively. There were no changes to the expenses or the net loss of the third quarter of 2003.

Compensation expense for options granted during 2003 was based on the estimated fair values at the time of the grant and the expense was recognized over the vesting period of the option. For options granted prior to January 1, 2003, the pro forma earnings impact of related stock-based compensation expense is as follows:

	<i>Year Ended December 31, 2003</i>	
Net income as reported (restated – see note 3)	\$	35,844
Stock-based compensation expense		(5,522)
Pro forma	\$	30,322
Net income per unit		
Basic as reported	\$	0.66
Pro forma	\$	0.56
Diluted as reported	\$	0.62
Pro forma	\$	0.52

The weighted average fair market value of options granted during the year ended December 31, 2003 was \$4.21 per option. The fair value of the stock options granted was estimated on the grant date based on the Black-Scholes option-pricing model using the following assumptions: risk free interest rate of 4.5 percent; expected life of four years; and expected volatility of 52 percent.

19. SUBSEQUENT EVENT

In January 2005, the Company entered into agreements to collar the exchange rate on US\$9 million per month at average \$CDN/\$US rates between \$1.2168 and \$1.2500.

20. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"), which differ in some respects from GAAP in the United States. The significant differences in GAAP, as applicable to these consolidated financial statements and notes, are described in the Trust's Form 40-F, which is filed with the United States Securities and Exchange Commission.

OIL AND GAS RESERVES

AS AT DECEMBER 31, 2004

The following tables summarize certain information with regard to Baytex's oil and gas reserves as evaluated by Sproule Associates Limited as at December 31, 2004. Additional information required under NI 51-101 is included in the Annual Information Form for fiscal 2004.

FORECAST PRICES AND COSTS ⁽⁴⁾

	Light and Medium Oil		Heavy Oil		Natural Gas Liquids	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾
	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)

RESERVES CATEGORY

Proved

Developed Producing	4,107.7	3,688.2	20,161.2	17,926.0	2,867.0	2,269.3
Developed Non-Producing	509.6	420.5	15,815.0	13,420.2	420.9	333.0
Undeveloped	1,768.9	1,527.9	19,898.0	17,877.5	384.6	306.6
Total Proved	6,386.2	5,636.5	55,874.2	49,223.7	3,672.5	2,908.9
Probable	2,430.8	2,165.3	24,887.1	21,840.4	590.2	454.1
Total Proved Plus Probable	8,817.0	7,801.7	80,761.3	71,064.2	4,262.7	3,363.1

	Natural Gas		Total Reserves ⁽³⁾	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾
	(Bcf)	(Bcf)	(MBoe)	(MBoe)

RESERVES CATEGORY

Proved

Developed Producing	95.5	79.0	43,060.7	37,047.9
Developed Non-Producing	7.6	6.3	18,019.4	15,231.8
Undeveloped	7.8	6.2	23,359.5	20,750.6
Total Proved	111.0	91.6	84,439.6	73,030.3
Probable	44.1	36.9	35,258.0	30,605.8
Total Proved Plus Probable	155.1	128.4	119,697.6	103,636.1

Notes:

- (1) Gross Reserves are the working interest share of the remaining reserves, before deduction of any royalties, and excluding any royalty interest.
- (2) Net Reserves are the gross remaining reserves of the properties which Baytex has an interest, less all Crown, freehold and overriding royalties and interests owned by others.
- (3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
- (4) Numbers may not add due to rounding.

RESERVES LIFE INDEX

	2005	Reserves Life Index (RLI) (years)	
	Production Target	Total Proved	Proved Plus Probable
Crude oil (bbls/d)	26,000	7.0	9.9
Natural gas (mmcf/d)	60.0	5.1	7.1
Oil equivalent (boe/d)	36,000	6.4	9.1

NET PRESENT VALUE OF RESERVES

Summary of Net Present Value of Future Net Revenue As at December 31, 2004 Forecast Prices and Costs

(\$ thousands)	Before Income Taxes Discounted at (%/year)			
	0%	5%	10%	15%
RESERVES CATEGORY				
Proved				
Developed Producing	668,600	596,300	538,500	493,600
Developed Non-Producing	180,600	148,200	125,100	107,800
Undeveloped	187,500	145,100	114,200	91,100
Total Proved	1,036,700	889,600	777,800	692,500
Probable	414,800	307,200	241,500	197,100
Total Proved Plus Probable	1,451,500	1,196,800	1,019,300	889,600

SPROULE DECEMBER 31, 2004 FORECAST PRICES

	WTI Cushing	Edmonton Par Price	Hardisty Heavy 12 API	AECO C-Spot	Inflation Rate	Exchange Rate
Year	US\$/Bbl	C\$/Bbl	C\$/Bbl	C\$/MMbtu	%/Yr	\$/US\$/Cdn
2005	44.29	51.25	28.91	6.97	2.5	0.840
2006	41.60	48.03	28.12	6.66	2.5	0.840
2007	37.09	42.64	26.19	6.21	2.5	0.840
2008	33.46	38.31	25.06	5.73	2.5	0.840
2009	31.84	36.36	23.60	5.37	1.5	0.840
2010	32.32	36.91	24.12	5.47	1.5	0.840
2011	32.80	37.47	24.64	5.57	1.5	0.840
2012	33.30	38.03	25.17	5.67	1.5	0.840

NET ASSET VALUE

The following net asset value calculation utilizes what is generally referred to as the "produce-out" net present value of Baytex's oil and gas reserves as evaluated by independent evaluators. It does not take into account the possibility of Baytex being able to recognize additional reserves in its existing properties beyond those included in the 2004 year-end report.

(\$ thousands)	Constant Prices ⁽¹⁾	Forecast Prices
Proved plus probable reserves ⁽²⁾	\$ 1,461,400	\$ 1,019,300
Undeveloped land ⁽³⁾	70,224	70,224
Net debt ⁽⁴⁾	(412,531)	(412,531)
Net asset value	\$ 1,119,093	\$ 676,993
Total trust units outstanding ⁽⁵⁾	68,817,072	68,817,072
Net asset value per trust unit	\$ 16.26	\$ 9.84

Notes:

- (1) The constant crude oil and natural gas benchmark reference prices utilized were: WTI – US\$43.45; Edmonton Par crude – \$46.53; Hardisty Heavy 12 API – \$32.97; AECO Gas – \$6.78; and exchange rate – \$0.8308.
- (2) As evaluated by Sproule as at December 31, 2004 discounted at 10%. Net present value of future net revenue does not represent fair market value of the reserves.
- (3) As evaluated by Baytex as at December 31, 2004 on 798,000 net acres of undeveloped land.
- (4) Long-term debt net of working capital as at December 31, 2004, excluding \$9.5 million of notional liabilities associated with the mark-to-market value of derivative contracts.
- (5) Includes 66,538,252 trust units outstanding as at December 31, 2004 plus 1,876,004 exchangeable shares converted at an exchange ratio of 1.21472.

RESERVES RECONCILIATION

The following table represents a reconciliation of company interest reserves by principal product type: ⁽³⁾⁽⁴⁾

FORECAST PRICES AND COSTS

Factors	Light and Medium Oil			Heavy Oil		
	Proved Plus			Proved Plus		
	Proved ⁽¹⁾ (Mbbbls)	Probable ⁽¹⁾ (Mbbbls)	Probable ⁽¹⁾ (Mbbbls)	Proved ⁽¹⁾ (Mbbbls)	Probable ⁽¹⁾ (Mbbbls)	Probable ⁽¹⁾ (Mbbbls)
December 31, 2003	5,159	1,649	6,808	57,568	23,606	81,174
Extensions	—	—	—	5,118	1,478	6,596
Improved Recovery	23	62	85	2,879	785	3,664
Technical Revisions	121	4	125	(477)	(661)	(1,138)
Acquisitions	2,538	777	3,315	11	4	15
Dispositions	(739)	(135)	(873)	—	—	—
Economic Factors	38	74	112	(915)	(324)	(1,240)
Production	(754)	—	(754)	(8,309)	—	(8,309)
December 31, 2004	6,386	2,431	8,817	55,874	24,887	80,761

Factors	Natural Gas Liquids			Natural Gas		
	Proved Plus			Proved Plus		
	Proved ⁽¹⁾ (Mbbbls)	Probable ⁽¹⁾ (Mbbbls)	Probable ⁽¹⁾ (Mbbbls)	Proved ⁽¹⁾ (Mmcft)	Probable ⁽¹⁾ (Mmcft)	Probable ⁽¹⁾ (Mmcft)
December 31, 2003	260	95	355	81,175	24,641	105,816
Extensions	—	—	—	3,884	2,558	6,441
Improved Recovery	—	—	—	541	20	561
Technical Revisions	14	(3)	11	1,663	3,972	5,635
Acquisitions	3,449	492	3,941	46,061	13,899	59,960
Dispositions	—	—	—	(130)	(85)	(215)
Economic Factors	(10)	7	(3)	(2,108)	(904)	(3,012)
Production	(41)	—	(41)	(20,087)	—	(20,087)
December 31, 2004	3,673	590	4,263	110,999	44,101	155,100

Factors	Oil Equivalent ⁽²⁾		
	Proved Plus		
	Proved ⁽¹⁾ (MBoe)	Probable ⁽¹⁾ (MBoe)	Probable ⁽¹⁾ (MBoe)
December 31, 2003	76,522	29,457	105,979
Extensions	5,766	1,904	7,670
Improved Recovery	2,993	850	3,843
Technical Revisions	(64)	1	(63)
Acquisitions	13,674	3,590	17,264
Dispositions	(760)	(149)	(909)
Economic Factors	(1,239)	(395)	(1,634)
Production	(12,452)	—	(12,452)
December 31, 2004	84,440	35,258	119,698

Notes:

- (1) Reserves information as at December 31, 2003 and 2004 is prepared in accordance with NI 51-101.
- (2) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf : 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
- (3) Company interest reserves include solution gas but do not include any royalty interest.
- (4) Numbers may not add due to rounding.

CORPORATE GOVERNANCE

The Board of Directors and Management of Baytex are committed to ensuring proper corporate governance practices that meet or exceed current regulatory requirements.

Our approach to corporate governance is to meet or exceed the guidelines recommended by the Toronto Stock Exchange (TSX) which were established in 1995 and modified in 1999. The TSX guidelines address such matters as the constitution and independence of the board, its functions, its committee structure, and the relationship between the board, management and investors.

Baytex will comply with all applicable regulations with a goal of providing transparency and accountability in our corporate governance practices.

MANDATE OF THE BOARD

The Baytex board of directors is responsible for the stewardship of Baytex including the Trust and subsidiaries. The board's mandate includes;

- the review and approval of strategic, operating, capital and financial plans;
- the identification of the principal risks of Baytex's operations and the review of risk management policies;
- the appointment of officers;
- the review of integrity of internal financial controls and management systems;
- the approval of acquisitions and dispositions;
- approval of capital expenditure budgets;
- the review of financing strategies; and
- approval of distribution policies.

The board holds regularly scheduled meetings to review the business affairs of Baytex. The Chairman of the board is an independent director and has a separate role from that of the President and Chief Executive Officer.

BOARD COMPOSITION

The board of directors of Baytex currently includes 6 members all of whom are independent except for Mr. Raymond Chan, President and Chief Executive Officer.

COMMITTEES

Individual directors are appointed by the board to sit on certain designated committees including the Audit Committee, Reserves Committee and Compensation Committee. Each committee has a written board approved mandate outlining its purpose, membership, responsibility and accountability.

AUDIT COMMITTEE

The Audit Committee has responsibility for overseeing:

- the nature and scope of the annual audit;
- management's reporting on internal accounting standards and practices;
- financial information and accounting systems and procedures;
- financial reporting and statements; and
- recommending for board approval the interim and audited annual financial statements and other mandatory disclosure containing financial information.

The Audit Committee is comprised of three directors, none of whom are members of the management of Baytex and all of whom are independent as per the definition contained in Multilateral Instrument 52-110. All members of the Audit Committee are financially literate as per the definition contained in Multilateral Instrument 52-110. The Baytex Audit Committee meets at least quarterly and may meet more frequently as required.

RESERVES COMMITTEE

The Reserves Committee has responsibility for;

- reviewing disclosure requirements and procedures with respect to oil and gas activities including those set forth under applicable securities legislation including National Instrument 51-101;
- reviewing procedures for providing information to the independent reserves evaluator;
- reviewing the appointment of the independent evaluator;
- recommending to the board of directors the approval of the annual independent reserves evaluation report and related information; and
- reviewing generally all matters relating to the preparation and public disclosure of reserves estimates.

The Reserves Committee is comprised of three directors, none of whom are members of the management of Baytex and all of whom are independent as per the definition contained in National Instrument 51-101. Each member of the Reserves Committee has sufficient technical knowledge of oil and natural gas reserves to perform their duties under this committee. The Reserves Committee meets at least annually and may meet more frequently as required.

COMPENSATION COMMITTEE

The purpose of the Compensation Committee is to review matters relating to the human resource policies and compensation of all directors, officers and employees of Baytex in the context of the approved budget and business plan. The Compensation Committee formulates and makes recommendations to the board regarding compensation and human resource issues.

The Compensation Committee is comprised of three directors, none of whom are members of the management of Baytex and all of whom are independent. The Compensation Committee meets at least annually and may meet more frequently as required.

CORPORATE GOVERNANCE POLICIES

POLICY ON BUSINESS CONDUCT AND ETHICS

The Baytex Policy on Business Conduct and Ethics is a statement of the principles to which Baytex is committed and is designed to direct all employees, officers and directors in the practice of ethical business conduct. The policy is a guide to the standards of behavior that we require in all of our business activities. Directors, officers and employees must know these standards and agree annually in writing to comply with the policy. The policy not only applies to Baytex employees, officers and directors but also to independent contractors to the extent that they conduct activities on behalf of Baytex.

DISCLOSURE, CONFIDENTIALITY AND TRADING POLICY

The Disclosure, Confidentiality and Trading Policy establishes procedures to permit the appropriate disclosure of information to the public in an informative, timely and broadly disseminated manner. The policy also ensures that non-public information remains confidential and that trading of Baytex securities by directors, officers and employees is conducted in compliance with applicable securities laws.

WHISTLE BLOWER POLICY

Baytex is committed to maintaining the highest standards of honesty and accountability in its business activities. Our employees, officers and directors are likely to be the first to know of when someone inside the Company or connected with the Company is acting improperly or illegally. Baytex maintains a procedure for the reporting of ethical violations which encourages all Baytex employees to report any misconduct. The procedure ensures that Baytex employees may report misconduct without the threat or fear of dismissal, harassment or other retaliation.

CODE OF ETHICS FOR PRINCIPAL EXECUTIVE OFFICER AND SENIOR FINANCIAL OFFICERS

While Baytex and its unitholders expect honest and ethical conduct in all aspects of our business from all employees, officers and directors, Baytex and its unitholders expect the highest possible standard from our financial managers. This code of ethics is applicable to the President and Chief Executive Officer, Vice President Finance and Chief Financial Officer, Controller and any other person performing a similar function. These individuals are setting an example for other employees and are expected to foster a culture of transparency, integrity and honesty. Compliance with this code is an essential condition of employment for the financial officers and any violations will be met with immediate sanction.

A complete copy of the Baytex corporate governance policies can be found on the Baytex website at www.baytex.ab.ca or by contacting the Investor Relations Department of Baytex.

BAYTEX DISTRIBUTION REINVESTMENT PLAN

Effective October 18, 2004, Baytex implemented a Distribution Reinvestment Plan ("DRIP"). The DRIP provides a convenient mechanism for unitholders to reinvest their monthly cash distributions in additional trust units. The DRIP permits the purchase of Baytex trust units from treasury at a discounted price. This plan is currently only available to Canadian resident unitholders.

The benefits to eligible Baytex unitholders under the DRIP are:

- Trust units purchased from treasury under the DRIP will be **issued at a 5 percent discount** from the weighted average closing price of the trust units on the Toronto Stock Exchange. In instances where Baytex elects to purchase trust units for the DRIP through the facilities of the Toronto Stock Exchange, rather than issuance from treasury, the price of trust units to participants will be the average market price of trust units during the period of up to 20 trading days following the relevant distribution record date. Generally, Baytex expects to issue trust units from treasury at the 5 percent discount to satisfy the requirements of the DRIP.
- Participants in the DRIP do not pay brokerage commissions or any costs associated with the administration of the plan. However, unitholders who enroll in the DRIP through a broker, trust company, bank or other nominee may be subject to fees in accordance with their agreement with their nominee.

Statements of account are mailed to each participating registered unitholder on a quarterly basis detailing the investment made on their behalf.

Beneficial owners of trust units whose trust units are not registered in their own names may participate in the DRIP by either: (a) having their trust units transferred into their own names or (b) by instructing their broker, trust company, bank or other nominee to participate in the DRIP on their behalf while maintaining the trust units in their nominee's account. **It is not necessary for beneficial owners of trust units to remove their trust units from their account with a broker or other nominee to enroll in the DRIP.**

Canadian unitholders may join the plan at any time by completing an enrollment form, or by having their nominee complete an enrollment form, and submitting it to Valiant Trust Company at 310, 606 – 4th Street S.W., Calgary, Alberta T2P 1T1 Attention: Income Trust Department Fax: (403) 233-2857. A detailed explanation of the terms and conditions of the DRIP and related enrollment forms are available on the Baytex website at www.baytex.ab.ca or by contacting the Investor Relations Department toll free at 1(800) 524-5521 or (403) 269-4282.

SAFETY, ENVIRONMENT AND COMMUNITY

Baytex Energy Trust has a formal policy to conduct its operations in a manner designed to protect the health and safety of its employees, contractors, and the public and to avoid an adverse impact on the environment.

In support of this policy, Baytex Energy Trust:

- ➔ has developed and maintains health, safety and environmental management plans which include practices and procedures that comply with regulatory requirements and industry standards;
- ➔ ensures that all employees and contract personnel understand their responsibilities through education, communication and training;
- ➔ has developed and maintains a contractor management program to ensure contractor and subcontractor compliance with Baytex policies;
- ➔ conducts regular review of the safety and environmental management system and conducts updates as required. Input from employees is encouraged and is considered when conducting reviews;
- ➔ conducts regular inspections and audits on all properties operated by Baytex; and
- ➔ has developed emergency response plans and employees have been trained to effectively respond to emergency situations.

Management is responsible for establishing health, safety and environmental policies and procedures and ensuring that all necessary resources, equipment and training is provided. In addition, corporate safety and environmental reports are presented on a quarterly basis to the Board of Directors. All employees and contractors must understand and comply with all applicable policies and procedures.

In addition to the above, Baytex participates in the Canadian Association of Petroleum Producer's Environment, Health and Safety Stewardship program. This program has been developed to set consistent safety and environmental standards throughout the Canadian oil and gas industry. The program allows industry participants to measure the quality and performance of its environment, health and safety programs against other companies. Baytex is proud to report that it has achieved a "Gold" ranking under this program for three years running.



COMMUNITY

Baytex believes in enhancing the communities where employees live and work. Baytex supports causes and institutions through financial and volunteer efforts. The Trust is very proud of these associations with many not-for-profit organizations. Baytex employs 104 full time office staff in Calgary and 20 full time field staff in other areas of Alberta and Saskatchewan.

Baytex encourages employees to contribute to their communities through volunteer work. Baytex regularly contributes to causes supported by its employees. Baytex also directs funding to non-profit organizations located in its key operational areas.

Baytex conducts a portion of its operations on aboriginal lands. Baytex maintains a mutually beneficial business relationship with the First Nations communities on these lands and the Trust is proud of these associations.

PRIVACY

Baytex respects and upholds an individual's right to privacy and to protection of personal information. Baytex is committed to ensuring compliance with applicable privacy legislation.

We do not use or disclose personal information for any purpose other than that for which it was collected, with consent or as required by law. Personal information is retained only as long as is necessary for the fulfillment of the purposes for which it was collected, or as required by law.

Baytex protects personal information with appropriate security safeguards. Safeguards include physical, administrative, and electronic security measures.

FIVE YEAR SUMMARY

Baytex Energy Trust commenced operations as an oil and gas income trust on September 2, 2003. As the Trust is the successor organization to Baytex Energy Ltd., results of the current period may not be directly comparable to those of the prior periods as certain assets were transferred out of Baytex pursuant to the Plan of Arrangement effective September 2, 2003.

FINANCIAL

(\$ thousands, except per share amounts)	2004	2003	2002	2001	2000
Petroleum and natural gas sales	\$ 420,400	\$ 403,022	\$ 372,037	\$ 338,686	\$ 286,226
Cash flow from operations ⁽¹⁾	136,012	138,233	191,086	144,070	155,326
Per unit/share – basic	2.17	2.56	3.65	2.91	3.68
Cash distributions paid or declared	113,063	33,382	–	–	–
Per unit	1.80	0.60	–	–	–
Net income (loss)	13,763	35,844	41,706	(140,454)	38,574
Per unit/share – basic	0.22	0.66	0.80	(2.84)	0.84
Capital expenditures, net	280,666	48,383	126,468	375,853	388,052
Total net debt	422,044	213,572	362,775	379,061	256,257
Total assets	1,104,136	982,640	997,760	967,046	829,227

OPERATIONS

Production

Light oil and NGLs (bbls/d)	2,172	2,273	3,154	5,152	4,107
Heavy oil (bbls/d)	22,703	23,911	23,967	26,533	20,005
Total oil and NGLs (bbls/d)	24,875	26,184	27,121	31,685	24,112
Natural gas (mmcf/d)	54.9	63.0	72.6	70.8	57.7
Barrels of oil equivalent (boe/d @ 6:1)	34,022	36,686	39,214	43,488	33,721

Reserves⁽²⁾

Crude oil and NGLs (mbbls)

Proved	65,933	62,987	104,584	110,221	105,022
Probable	27,908	25,350	25,637	26,167	24,019
Total	93,841	88,337	130,221	136,388	129,041

Natural gas (mmcf)

Proved	110,999	81,175	75,573	134,653	98,048
Probable	44,101	24,641	13,521	21,384	15,101
Total	155,100	105,816	89,094	156,037	113,149

Wells drilled (gross)

Oil	104	173	106	63	267
Gas	16	67	51	81	28
Other	7	7	3	3	4
Dry	11	19	26	32	23
Total	138	266	186	179	322

(1) Cash flow from operations is a non-GAAP term that represents cash generated from operating activities before changes in non-cash working capital and other operating items. The Trust's cash flow from operations may not be comparable to other companies. The Trust considers cash flow a key measure of performance as it demonstrates the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

(2) Reserves information from 2000 to 2002 is prepared in accordance with National Policy 2-B. Probable reserves presented herein for those years represents 50 percent of the total probable reserves then assigned to allow more appropriate comparison with probable reserves under NI 51-101 as at December 31, 2003.

THE BAYTEX TEAM

Suzanne Adams	Jeremy Gizen	Paulette Moody
Shannon Aldridge	Henry Goeckel	Wayne Moore
Terra Altshuler	Tanya Goertzen	Emmanuel Moundjian
Jonathan Anderson	Kevin Golem	Joanna Nadgrodkiewicz
David Baldwin	Amy Gowertz	Ron Naeth
Daniel Belot	Vernon Haberlack	Miriam Olino
Julie Benoit	Michael Hanson	Leanne Oman
Crystal Berg	Clint Harris	Carrie Parker
Randy Best	Brad Heck	Scott Patterson
Joanna Bil	Neil Higdon	Paula Peet
Valerie Black	Tisha High	Jonathan Pemberton
Tobi Boake	Scott Hopkins	Karen Pihl
Aaron Bone	Ronald Hornseth	Paul Poohkay
Bradley Boyce	Craig Huggard	Angela Popilian
Paulette Broda	Carey Jolly	Ken Potratz
Stephen Brownridge	Lisa Kennedy	Susan Predika
Daniel Brule	Carolyn Keough	Chris Quon
Susan Bunyan	Bruce Kernohan	Barbara Rackham
Tracy Campbell	Kyle Kerpan	Colin Rae
Mitchell Carter	Tracee Killam	Lorne Resnechenko
Raymond Chan	Barb Kimmett	Heather Ross
Ringo Chiu	Becky Kissisk	Allan Ruus
Farah Choudhry	Shaun Kozan	Lee Schiefner
Christine Clancy	Terry Kreese	Patrick Schmaltz
Robert Clark	William Krepps	Ric Sebastian
Keith Clausen	Andrey Kunda	John Shears
Jennifer Clee	Dawn Lashmar	John Skoreyko
Michael Clegg	Paul Lawrence	Arta Staffa
Karen Collins	Linda Lee	Rod Swenson
Steve Corti	Jim Lehman	Cheryl Swenson
Grant Cutforth	David Leung	Ross Thompson
Sean Darragh	Jennifer Lindsay	Jill Thompson
Francesca Derimini	Michael Longeway	Tania Thompson
Chantal Desmarais	Ramona Lui	Shelley Thomson
Ken Doig	Barbara MacBeath	Susan Tischner
Michelle Dowdell	Drew MacGregor	Amelia Trinidad
Shane Draganuk	Dave MacKenzie	James Tymchak
Derek Dube	Colleen Mah	Jacquelyn Verner
Dean Dueck	Yvonne Manchul	Janet Vetter
Patricia Dumais	Anthony Marino	Josh Wagman
Tania Dunlop	Paul Martin	Sean Ward
Susan Ehlers	Darron Mazurek	Shelley Ward
Dorin Eibenschutz	Jill McAuley	Mike Wilcox
Russell Emmerson	Robert McCallum	Kathleen Wilmot
Marilyn Ennis	Brett McDonald	Tim Wilson
Cheryl Ferguson	Lionel McKenzie	Tiffany Wolgien
Graham Foster	Brian McKinnon	Wendy Woolsey
Laura French	Natasha Mercer	Verna Yee
Dave Friesen	Maynard Metchewais	Chris Young
Amy Germain	Jerilee Miller	Gloria Ziegler
Ralph Gibson	David Mitchell	

DIRECTORS AND OFFICERS

BOARD OF DIRECTORS

JOHN A. BRUSSA⁽²⁾⁽³⁾

Partner

Burnet, Duckworth & Palmer LLP

W.A. BLAKE CASSIDY⁽¹⁾

Retired Banker

RAYMOND T. CHAN

President and CEO

Baytex Energy Trust

EDWARD CHWYL⁽²⁾⁽³⁾

Chairman of the Board

Independent Businessman

NAVEEN DARGAN⁽¹⁾⁽²⁾

Independent Businessman

DALE O. SHWED⁽¹⁾⁽³⁾

President and CEO

Crew Energy Inc.

(1) Member of the Audit Committee

(2) Member of the Compensation Committee

(3) Member of the Reserves Committee

OFFICERS

RAYMOND T. CHAN

President and CEO

DANIEL G. BELOT

Vice President, Finance and CFO

RANDAL J. BEST

Vice President, Corporate Development

RALPH W. GIBSON

Vice President, Marketing

ANTHONY W. MARINO

Chief Operating Officer

SHANNON M. GANGL

Secretary

Partner

Burnet, Duckworth & Palmer LLP

CORPORATE INFORMATION

HEAD OFFICE

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Calgary, Alberta T2P 2V7

Phone: 403-269-4282

Fax: 403-205-3845

Website: www.baytex.ab.ca

Toll-free: 1-800-524-5521

AUDITORS

Deloitte & Touche LLP

BANKERS

The Toronto-Dominion Bank
BNP Paribas (Canada)
National Bank of Canada
Royal Bank of Canada
Union Bank of California

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Associates Limited

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: BTE.UN

ABBREVIATIONS

API	American Petroleum Institute
bbls	barrels
bbls/d	barrels per day
bcf	billion cubic feet
boe*	barrels of oil equivalent
boe/d*	barrels of oil equivalent per day
Capex	capital expenditures
FD&A costs	finding, development and acquisition costs
F&D	finding and development costs
GAAP	generally accepted accounting principles
G&A	general and administrative
GJ	gigajoule
LLB	Lloyd Light Blend
mbbls	thousand barrels
mboe*	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbbls	million barrels
mmbse*	million barrels of oil equivalent
mmbtu	million British Thermal Units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NAV	net asset value
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange
RLI	reserve life index
WTI	West Texas Intermediate

BOEs may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio for natural gas of 6mcf:1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

ADVISORY

Certain statements in this report are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this report contains forward-looking statements relating to Management's approach to operations, expectations relating to the number of wells, amount and timing of capital projects, foreign exchange rates, interest rates, worldwide and industry production, prices of oil and gas, heavy oil differentials, company production, cash flow, debt levels and distribution practices. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the ability to produce and transport crude oil and natural gas to markets; the result of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the imprecision of reserve estimates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; change in environmental and other regulations; risks associated with oil and gas operations; the weather in the Trust's areas of operations; and other factors, many of which are beyond the control of the Trust. There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast.

BAYTEX

ENERGY TRUST

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